STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.	)	Case No. U-18014

NOTICE OF PROPOSAL FOR DECISION

The attached Proposal for Decision is being issued and served on all parties of record in the above matter on November 21, 2016.

Exceptions, if any, must be filed with the Michigan Public Service Commission, 7109 West Saginaw, Lansing, Michigan 48917, and served on all other parties of record on or before December 8, 2016, or within such further period as may be authorized for filing exceptions. If exceptions are filed, replies thereto may be filed on or before December 22, 2016. **The Commission has selected this case for participation in its Paperless Electronic Filings Program. No paper documents will be required to be filed in this case.**

At the expiration of the period for filing exceptions, an Order of the Commission will be issued in conformity with the attached Proposal for Decision and will become effective unless exceptions are filed seasonably or unless the Proposal for Decision is reviewed by action of the Commission. To be seasonably filed, exceptions must reach the Commission on or before the date they are due.

MICHIGAN ADMINISTRATIVE HEARING SYSTEM
For the Michigan Public Service Commission

Sharon L. Feldman

Sharon L. Feldman
Administrative Law Judge

November 21, 2016
Lansing, Michigan

S T A T E O F M I C H I G A N

MICHIGAN ADMINISTRATIVE HEARING SYSTEM

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of	)	
DTE Electric Company for authority	)	
to increase its rates, amend its rate	)	
schedules and rules governing the	)	Case No. U-18014
distribution and supply of electric	)	
energy, and for miscellaneous	)	
accounting authority.	)	

PROPOSAL FOR DECISION

Issued and Served: November 21, 2016

TABLE OF CONTENTS

S T A T E O F M I C H I G A N

MICHIGAN ADMINISTRATIVE HEARING SYSTEM

FOR THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.	)))))))	Case No. U-18014

PROPOSAL FOR DECISION

I.

PROCEDURAL HISTORY

On February 1, 2016, DTE Electric Company (DTE) filed a rate application requesting a $344 million revenue increase, and other relief. The rates requested in the application are based on an August 1, 2016 through July 31, 2017 projected test year. The most recent rate case orders for DTE were issued by the Commission on December 11, 2015, January 19, 2016, and February 23, 2016, in Case No. U-17767.

Staff, DTE, and potential intervenors attended the March 3, 2016 prehearing conference. Intervention was granted to Attorney General Bill Schuette (Attorney General); the Michigan Cable Telecommunications Association (MCTA); the Association of Businesses Advocating Tariff Equity (ABATE); the Municipal Street Lighting Coalition; the Michigan Environmental Council (MEC); the Natural Resources Defense Council (NRDC); the Sierra Club (SC); Energy Michigan; Local 223, Utility Workers Union of

America, AFL-CIO (UWUA); the Kroger Company (Kroger);[1] Detroit Public Schools (DPS); Wal-Mart Stores East, LP and Sam's East, Inc. (Walmart); and the Residential Customer Group (RCG). The parties agreed to a schedule meeting the time limits of MCL 460.6a.

Following the prehearing conference, the schedule for the self-implementation hearing was adjusted slightly by agreement of the parties, and the schedule for filing Staff and intervenor testimony was also extended slightly by agreement of the parties. Also following the prehearing conference, the Environmental Law & Policy Center filed a late-filed petition to intervene, which was granted by ruling dated May 23, 2016, and which was subsequently withdrawn. In addition, the ALJ entered a protective order on July 12, 2016, after all parties indicated that they did not object.

On July 1, 2016, DTE filed the testimony and exhibits of Don M. Stanczak, Vice President for Regulatory Affairs at DTE Energy, explaining the company's plans to self-implement a revenue increase of $245 million effective August 1, 2016. At the July 11, 2016 hearing on this self-implementation filing, Mr. Stanczak's testimony was bound into the record without any cross-examination, and his supporting Exhibits A-24 and A-25 were admitted into evidence.[2]

By the July 5, 2016 filing deadline, Staff and the following intervenors filed direct testimony and exhibits: Energy Michigan; Kroger; Walmart; MEC, the Sierra Club, the Natural Resources Defense Council; ABATE; the Attorney General; and the Residential Customer Group. At the evidentiary hearings held on August 10, 11, 15, and 16, 2016,

[1] Kroger did not attend the prehearing conference, but asked the ALJ in advance to take up its intervention petition. Since no party objected, the intervention was granted.
[2] See 2 Tr 21-38. Mr. Stanczak's qualifications are set forth at 2 Tr 27-29 and 4 Tr 1080-1082.

12 witnesses appeared for cross-examination, while the testimony of the remaining 34 witnesses was bound into the record by agreement of the parties.

The parties filed briefs and reply briefs on September 19 and October 3, 2016, in accordance with a modified schedule. The following parties filed briefs: DTE, Staff, ABATE, the Attorney General, Energy Michigan, Kroger, Walmart, MEC/SC/NRDC, the Detroit Public Schools, and the Residential Customer Group.[3] The following parties filed reply briefs: DTE, Staff, ABATE, the Attorney General, Walmart, MEC/SC/NRDC, and the Residential Customer Group.

An overview of the record and the positions of the parties is presented below.

II.

OVERVIEW OF THE RECORD

The evidentiary record in this proceeding is contained in 2031 pages of transcript in 6 volumes, and 178 exhibits admitted into evidence. The discussion that follows reviews the direct testimony presented by each party, and then reviews the rebuttal testimony. This section is intended to provide a general overview; the record is discussed in further detail as necessary in the subsequent sections.

A. DTE Electric

DTE reduced its requested revenue increase from the $344 million initially filed to $326.1 million in its brief and then to $325.2 in its reply brief. The utility's revised rate request is based on a jurisdictional rate base of approximately $14.4 billion, a return on equity of 10.5% with an overall cost of capital of 5.71%, and an adjusted net operating income of $616 million. DTE presented a cost of service study and proposed numerous

[3] The RCG filed its brief just after midnight of the due date attributing the late filing to an IT problem.

rate design and tariff changes. The company is also seeking future ratemaking treatment for various categories of expenses, other accounting approvals, and various tariff changes.

DTE presented the testimony of 21 witnesses, and 36 exhibits including the company's self-implementation exhibits. Many of these exhibits include multiple schedules. Mr. Stanczak, who presented the self-implementation testimony noted above, testified that the key factors contributing to the revenue deficiency include increased investments in net plant--including what he characterized as "electric reliability investments" in the distribution system and generation fleet--working capital, associated depreciation and property tax increases, and an increase in Operations and Maintenance (O&M) expense. Mr. Stanczak also addressed the company's proposal to revise the allocation method for production costs, and proposed a Revenue Decoupling Mechanism (RDM) in anticipation of authorizing legislation. Mr. Stanczak presented an overview of the company's filing including a summary of the testimony accompanying the filing.

Paul G. Horgan, Director of Regulatory Operations for DTE Energy Corporate Services, LLC, presented the revenue requirements calculation supporting DTE's filed revenue deficiency, shown in Exhibit A-8, with a rate base of $14.5 billion, adjusted net operating income of $616 million, and an overall rate of return of 5.71%.[4] He also presented required historical schedules included in Exhibits A-1 through A-4, and identified the major components of DTE's rate request both in comparison to the rates approved in Case No. U-17767, and in comparison to the historical 2014 test year

[4] Mr. Horgan's testimony is transcribed at 4 Tr 1209-1233; his qualifications are set forth at 4 Tr 1210-1213.

revenue sufficiency. His Exhibit A-10, Schedule C2 shows the calculation of the revenue conversion factor of 1.6394.

Marcus B. Leuker, Manager of Corporate Energy Forecasting, presented the company's sales, demand, and system output forecasts for the projected test year, and through 2026, presented in his Schedules E1 and E2 of Exhibit A-12. He testified regarding the modeling and economic assumptions used in the forecasting, and presented Schedule E3 to show the changes from the 2014 historical data to his test year projections, and Schedule E4 to show the key assumptions underlying the forecasts.

Several witnesses provided testimony to support the company's projected capital and operating and maintenance (O&M) expense projections through the 2016-2017 test year. Franklin D. Warren, Vice President in charge of Fossil Generation for DTE, testified regarding the company's non-nuclear generation system capital and operating expense requirements including steam, hydraulic, and other non-nuclear power production plant. He categorized projected capital expenses into "routine" and "non-routine" categories for each plant type as shown in his Schedule B6.1 of Exhibit A-9.[5] Mr. Warren reviewed the company's recent and planned environmental compliance expenditures. He also presented capacity forecasts, including an analysis based on "summer capability", and a review of recent and planned unit retirements, recent purchases, and unit upgrades. Regarding O&M expenses broken down into "operating" and "maintenance" categories for each production type, he testified that historical

[5] Mr. Warren's testimony, including his rebuttal testimony and cross-examination, is transcribed at 3 Tr 80-200; his qualifications are set forth at 3 Tr 86-88.

expenses were adjusted for inflation and for "known and measurable" changes presented in his Schedules C5.1, 5.4, and 5.5 of Exhibit A-10.

Irene M. Dimitry, Vice President in charge of Business Planning and Development for DTE Energy Corporate Services, LLC, testified regarding DTE's request to recover certain projected capital costs.[6] She testified that DTE is asking to recovery projected capital expenditures to develop new renewable energy resources above the requirements of 2008 PA 295, including project evaluation and siting expenses, as presented in her Schedule B6.7 of Exhibit A-9. She testified that DTE is also asking to recover the capital costs associated with certain demand-side management (DSM) programs, presented in her Schedule B6.12 of Exhibit A-9. Ms. Dimitry also testified that DTE is asking to include the unamortized balance of its Fermi 3 Combined Operating License (COL) costs in working capital to a recover a return "on" as well as "of" the licensing costs. In addition, Ms. Dimitry testified in support of two O&M expense items DTE has included in its rate request: funding for economic development activities, included in Schedule C5.7 of Exhibit A-10 sponsored by Mr. Sparks; and funding for additional evaluation and planning activities for the federal Clean Power Plan requirements and for integrated resource planning (IRP) included in Mr. Warren's Schedule C5.1 of Exhibit A-10.

David C. Milo, Fuel Resource Specialist in the Operations and Logistics section of DTE's Fuel Supply Department, testified regarding DTE's historical and projected non-nuclear fuel supply capital and operating expenses including MERC expenses.[7] He

[6] Ms. Dimitry's testimony, including her rebuttal testimony and cross-examination, is transcribed at 3 Tr 202-268; her qualifications are set forth at 3 Tr 207-208.

[7] Mr. Milo's testimony is transcribed at 4 Tr 1131-1140; his qualifications are set forth at 4 Tr 1132-1133.

presented capital cost projections in Schedule B6.8 of Exhibit A-9 and O&M expense projections in Schedule C5.2 of Exhibit A-10.

Wayne A. Colonnello, Director of Nuclear Support for DTE, presented testimony addressing the company's capital and operating expense requirements associated with the Fermi 2 nuclear plant as shown in Schedules B6.2 of Exhibit A-9 and C5.3 of Exhibit A-10.[8] Mr. Colonnello also testified to support the costs to be recovered through the nuclear surcharge showing the proposed reduction in total costs to be recovered through this charge in his Exhibit A-19.

Paul Whitman, Director of Electrical Engineering and Planning for DTE which is a department newly formed in 2016, testified regarding distribution system capital and operating expense requirements reviewing reliability metrics for DTE, its vegetation management plans, and other changes forecast for the 2016/2017 test year.[9] The projected capital expenditures Mr. Whitman testified in support of are presented in his Schedule B6.3 of Exhibit A-9 while the O&M expenses he testified in support of are presented in his Schedule C5.6 of Exhibit A-10. Additional information Mr. Whitman presented regarding distribution system maintenance is included in Exhibit A-21.

Jeffrey C. Wuepper, Director of Compensation and Benefits for DTE Energy Corporate Services, LLC, testified regarding active employee compensation including health care costs and other employee benefits as well as incentive compensation plans and associated costs DTE is requesting to include in rates.[10] Mr. Wuepper also testified

---

[8] Mr. Colonnello's testimony, including his rebuttal testimony and cross-examination, is transcribed at 5 Tr 1251-1279 ; his qualifications are set forth at 5 Tr 1252-1254.

[9] Mr. Whitman's testimony, including his rebuttal testimony and cross-examination, is transcribed at 3 Tr 270-399; his qualifications are set forth at 3 Tr 276-279.

[10] Mr. Wuepper's testimony, including his rebuttal testimony, is transcribed at 4 Tr 905-983; his qualifications are set forth at 4 Tr 906-907.

regarding retiree benefits including pension expense and other post-employment benefits (OPEB). Mr. Wuepper's projected O&M expenses are in schedules C5.9, 5.10, and 5.11 of Exhibit A-10 while additional information and his analysis he presented regarding the company's incentive compensation plans are included in Exhibit A-20.

Robert E. Sitkauskas, General Manager of the Advanced Metering Infrastructure Group in the Major Enterprise Projects Organization of DTE, testified to describe DTE's Advanced Metering Infrastructure (AMI) progress and plans to support projected capital and operating expense and to recommend no change in the opt-out program[11]. Projected AMI capital expenditures through the test year are included in his Schedule B6.6 of Exhibit A-9 while projected O&M expenses are included in Schedule C5.13 of Exhibit A-10. Mr. Sitkauskas also presented an updated cost-benefit analysis in Schedule J1 of his Exhibit A-18, a financial summary of expenditures in Schedule J2 of this exhibit, and a summary of opt-out program costs in Schedule J3 of this exhibit.

Theresa M. Uzenksi, Manager of Regulatory Accounting for DTE Energy Corporate Services, LLC, presented 2014 historical balance sheet and net operating income statements with normalizing adjustments including most of the historical schedules included in Exhibits A-2 and A-3.[12] She testified to support certain accounting treatments including continued deferral of OPEB expense projections, regulatory asset treatment for certain tree-trimming expenses, creation and amortization of an obsolete inventory regulatory asset, capital treatment for certain DSM equipment,

[11] Mr. Sitkauskas's testimony, including his rebuttal testimony, is transcribed at 4 Tr 1022-1049; his qualifications are set forth at 4 Tr 1023-1024.
[12] Ms. Uzenksi's testimony, including her rebuttal testimony and cross-examination, are transcribed at 4Tr 779-902; her qualifications are set forth at 4 Tr 784-786.

and Power Supply Cost Recovery (PSCR) cost treatment for fuel costs associated with negative net generation.

Ms. Uzenski also testified specifically regarding capital and operating expense requirements for the Corporate Services Group programs including Customer 360 program expenditures, other software and IT expenditures, National Electric Reliability Council (NERC) critical infrastructure expenditures, and office and service center renovations. Ms. Uzenski's Schedule B6.5 of Exhibit A-9 summarizes projected capital expenditures for the Corporate Support Group. Her schedule C-5.8 of Exhibit A-10 presents projected O&M expenses for the corporate Support Group, other than employee benefits, including property insurance and injuries and damages expense categories. She also explained how common costs are allocated among DTE Energy subsidiaries.

Ms. Uzenski's also supported key summary schedules. Schedule B5 of Exhibit A-9 projects the company's test year beginning and ending balance sheet including total utility plant and property, other property and investments, current assets, and deferred debits. Her Schedule B6 of Exhibit A-9 summarizes the company's proposed capital expenditures through the test year based on projections sponsored by other witnesses. Ms. Uzenksi's Exhibit A-10 Schedule C1 presents DTE's filed forecast adjusted net operating income of $616.4 million based on O&M expense projections sponsored by several witnesses, depreciation and amortization expenses Ms. Uzenski presented in Schedule C6 of Exhibit A-10, tax expenses as presented by Mr. Heaphy, and revenue projections using Mr. Leuker's sales forecasts and the revenues approved in

Case No. U-17767. She also testified regarding the inflation factors DTE used in its expense projections relying on information from Mr. Wuepper and Mr. Leuker.

Jason E. Sparks, Manager of the Revenue Management Strategy section for DTE Energy Corporate Services, LLC, testified to support requested O&M expense levels for customer service and marketing operations within DTE, including customer service, billing, and uncollectible expense, presented in his Schedule C5.7 of Exhibit A-10.[13] He also testified regarding the company's low-income customer initiatives including continuation of the Low Income Pilot approved in Case No. U-17767.

Mark W. Heaphy, Manager of Tax Accounting for DTE Energy Corporate Services, LLC, testified to present DTE's historical and projected federal, state, and municipal income tax, property tax, and other tax expenditures.[14] He also explained the impact of the extension of the federal bonus depreciation deduction and the research tax credit, and discussed the Michigan Supreme Court's opinion regarding DTE's use tax obligations.

Edward J. Solomon, Assistant Treasurer and Director of Corporate Finance, Insurance and Development for DTE Energy and its subsidiaries, testified regarding DTE's capital structure and debt costs.[15] He presented the historical capital cost schedules in Exhibit A-4, Schedules D2 through D5, showing the cost of long-term and short-term debt and the authorized return on equity as of December 31, 2014. He testified in support of using a projected permanent capital structure for ratemaking with 50% debt and 50% equity. He testified that this is reflected in Mr. Horgan's Schedule

[13] Mr. Sparks's testimony is transcribed at 4 Tr 1006-1020; his qualifications are set forth at 4 Tr 1007.
[14] Mr. Heaphy's testimony, including his rebuttal, is transcribed at 4 Tr 986-1004; his qualifications are set forth at 4 Tr 987-988.
[15] Mr. Solomon's testimony is transcribed at 4 Tr 1106-1129; his qualifications are set forth at 4 Tr 1107-1109.

D1 of Exhibit A-11. He emphasized the importance of a financially sound capital structure to attract capital and provided his view of the risks facing DTE. In his Schedules D-2 and D3 of Exhibit A-11, he presented the projected costs of long-term and short-term debt. His Exhibit A-17 contains information regarding DTE's credit ratings, recent long-term debt offerings, and historical and other information to comply with Commission filing requirements.

Dr. Michael J. Vilbert, Principal with The Brattle Group, testified to explain and support DTE's requested return on equity of 10. 5%.[16] He discussed his view of the current market relationships between risk and return in light of recent events and his view of the risks facing DTE. He presented several analyses of the cost of equity using a proxy group of companies, including a discounted cash flow (DCF) analysis and a "risk-positioning" analysis, each with multiple models and assumptions. For each model and set of assumptions, he computed the After Tax Weighted Average Cost of Capital for each proxy company and derived his range of results using DTE's projected capital structure and a projected cost of long-term debt. He presented his analyses in Schedules D6.1 through D6.13 of Exhibit A-11.

Keegan O. Farrell, Principal Financial Analyst for Load Research at DTE Energy Corporate Services, LLC, presented the 2014 historical allocation schedules, which are included in his Exhibit A-5, and he presented the forecast test-year allocation schedules, which are included in his Exhibit A-16 and used in the company's cost of service study.[17] Mr. Farrell's testimony described the data he used and reviewed key

[16] Dr. Vilbert's testimony, including his rebuttal testimony and cross-examination, is transcribed at 4 Tr 563-726; his qualifications are set forth at 4 Tr 571 and 4 Tr 628-643.
[17] Mr. Farrell's testimony is transcribed at 4 Tr 1190-1207; his qualifications are set forth at 4 Tr 1191-1192.

terminology. He testified that he relied on Mr. Leuker's forecast of sales for the projected test year, while he developed class-level demand values by applying historic load factors to the forecast energy values, with one adjustment to reflect a large customer movement.

Thomas W. Lacey, Principal Financial Analyst for DTE Energy Corporate Services, LLC, presented the company's class cost of service study.[18] The historical cost allocations by rate class are included in Exhibit A-5 and the allocations of DTE's projected test-year costs are included in Exhibit A-13. Mr. Lacey also presented Schedule F1.3 in Exhibit A-13 to show total customer-related costs by class, which DTE used to derive the monthly customer charges. He testified that he used the "minimum-size distribution system method" for allocating distribution plant, acknowledging that DTE proposed this method for determining customer charges in Case No. U-17767 and it was rejected by the Commission.

Michael Williams, Principal Financial Analyst for DTE Energy Corporate Services, LLC, testified to support the rate design and tariffs for residential programs including increases in the monthly customer charges.[19] He sponsored portions of the rate design schedules in Exhibit A-14 and the tariffs in Exhibit A-15.

Kelly A. Holmes, Principal Financial Analyst for Regulatory Economics at DTE Energy Corporate Services, LLC, testified to support the rate design and tariffs for commercial secondary customers.[20] She sponsored portions of the rate design and

---

[18] Mr. Lacey's testimony, including his rebuttal and cross-examination, is transcribed at 3 Tr 400-456; his qualifications are set forth at 3 Tr 405-407.
[19] Mr. Williams's testimony is transcribed at 4 Tr 1051-1062; his qualifications are set forth at 4 Tr 1052-1053.
[20] Ms. Holmes's testimony is transcribed at 4 Tr 1064-1077; her qualifications are set forth at 4 Tr 1065-1067.

tariff schedules in Exhibits A-14 and A-15. She also testified to the calculation of power supply costs presented in Schedules C4 and C5.14.

Timothy A. Bloch, Principal Financial Analyst for DTE Energy Corporate Services, LLC, testified in support of the rate design and tariffs for primary customers, also sponsoring schedules included in Exhibits A-14 and A-15.[21] Mr. Bloch also presented a calculation of the proposed revised nuclear surcharge shown in Schedule F6 of exhibit A-14.

Kenneth D. Johnston, Manager of Community Lighting for DTE, testified in support of the proposed rate design and tariffs for the outdoor lighting rate schedules and proposed capital and O&M expenditures for his Community Lighting group.[22] His Schedule B6.4 of Exhibit A-9 reflects the proposed capital expenditures, while his Schedule C5.6 of Exhibit A-10 reflects the proposed O&M expenses. His proposed rate design is included in Schedule F3 of Exhibit A-14, while the proposed tariff revisions are included in Schedule G1 of Exhibit A-15. He also presented information regarding DTE's outage rates for lighting forecast for and its energy forecast for lighting and traffic signal rates in his Exhibit A-22.

Mr. Bloch, Mr. Colonnello, Ms. Dimitry, Mr. Heaphy, Mr. Johnston, Mr. Lacey, Mr. Leuker, Mr. Sitkauskas, Ms. Uzenski, Dr. Vilbert, Mr. Warren, Mr. Whitman, and Mr. Wuepper also presented rebuttal testimony as discussed below. Witnesses Bloch, Colonnello, Dimitry, Lacey, Leuker, Uzenski, Vilbert, Warren and Whitman were cross-examined on their testimony.

[21] Mr. Bloch's testimony, including his rebuttal and cross-examination, is transcribed at 3 Tr 457-551; his qualifications are set forth at 3 Tr 462-465.

[22] Mr. Johnston's testimony, including his rebuttal testimony, is transcribed at 4 Tr 1143-1188; his qualifications are set forth at 4 Tr 1144-1150.

B. Staff

Staff's filing recommended a revenue deficiency of $188.9 million based on a projected test year rate base of $14.3 billion, a return on equity of 10%, and adjusted net operating income of $673 million as shown in Exhibit S-1 Schedule A1. Staff also presented a cost of service study and rate design recommendations. Staff's briefs recommend additional adjustments to the revenue deficiency calculation. Staff presented the testimony of 15 Staff members and 13 exhibits, which include multiple schedules with decimal numbering.

Robert F. Nichols II, Manager of the Revenue Requirements Section of the Financial Analysis and Audit Division of the MPSC, presented Staff's revenue requirement calculations including Staff's projected revenue deficiency in Exhibit S-1 (Schedule A1), rate base in Exhibit S-2 (Schedule B1), and projected net operating income at current rates in Exhibit S-3 (Schedule C1), also relying on testimony from several other Staff witnesses for various components.[23] Mr. Nichols testified in support of DTE's request to capitalize and amortize DSM programmable thermostats over five years and presented Staff's implementation of the Commission's order in Case No. U-18033 regarding the treatment of obsolete inventory. Mr. Nichols also testified that Staff opposes DTE's request for specific funding for economic development activities.

Jay S. Gerken, an auditor in the Revenue Requirements section of the Financial Analysis and Audit Division of the MPSC, presented Staff's recommended total electric utility plant, including the accumulated provision for depreciation and the working capital

[23] Mr. Nichols's testimony is transcribed at 5 Tr 1519-1530; his qualifications are set forth at 5 Tr 1520-1522.

allowance, and Staff's recommended depreciation and amortization expense.[24] He explained that Staff's recommended $56.5 million reduction to the total utility plant presented by DTE is attributable to adjustments recommended by Staff witnesses Trachsel, Krause, Matthews, Mazuchowski, and Simpson. He testified that Staff's capital expense adjustments are also reflected in Staff's recommended accumulated provision for depreciation along with Staff's obsolete inventory adjustment and Staff's corrections to certain depreciation rates. Mr. Gerken also testified that Staff's recommended $141 million reduction to DTE's proposed working capital allowance includes exclusion of DTE's investment of $3.3 million in the Detroit Investment Fund as well as adjustments attributable to Staff's recommendations regarding tree-trimming expenses, obsolete inventory, and the Combined Operating License (COL) expenditures for a potential Fermi 3. Regarding depreciation and amortization expense, he testified that Staff's recommendation reflects Staff's capital expenditure adjustments and corrections to the depreciation rates.

Naomi J. Simpson, Public Utilities Engineer in the Generation and Certification of Need Section of the MPSC's Electric Reliability Division, presented Staff's recommendations regarding DTE's projected non-nuclear generating plant capital expenditures.[25] She testified that Staff recommends removing all contingency expenses from the non-routine capital expense category in DTE's Exhibit A-9, Schedule B6.1, shown in Staff Exhibit S-13, Schedule 13.0, and recommends no other changes to DTE's projected expenditures. She testified that Staff also requests that DTE conduct

[24] Mr. Gerken's testimony is transcribed at 5 Tr 1470-1481; his qualifications are set forth at 5 Tr 1471-1474.
[25] Ms. Simpson's testimony is transcribed at 5 Tr 1551-1561; her qualifications are set forth at 5 Tr 1552-1555.

biannual meetings with Staff after the conclusion of this case regarding its potential future environmental projects. She testified that Staff supports the non-contingency cost projections for DTE's proposed "new build" capital expenditures for research and development of a new power generation facility. Ms. Simpson also testified that Staff supports the company's request for additional funding for integrated resource planning activities further recommending that DTE "take a proactive role in providing regular updates and outreach regarding its IRP modeling assumptions, scenarios, sensitivities, and subsequent results." She presented additional audit and discovery responses from the company in the remaining schedules of her Exhibit S-13.

Katie Trachsel, an auditor in the Renewable Energy Section of the MPSC's Electric Reliability Division, testified regarding DTE's projected capital expenditure for its Distributed Customer Generation program.[26] She recommended rejecting the proposed $2.5 million expenditure on several grounds including duplication with funding approved in Case No. U-17767, the lack of results from the prior funding, and a lack of confidence that the funds will actually be expended in the projected test year.

Kevin S. Krause is also an auditor in the Renewable Energy Section of the MPSC's Electric Reliability Division.[27] He testified that although Staff supports the company's addition of more renewable energy to its generation portfolio, Staff removed DTE's proposed capital expenditures for renewable generation from this case because the company has requested recovery in an Act 295 proceeding. He testified that if

[26] Ms. Trachsel's testimony is transcribed at 5 Tr 1563-1569; her qualifications are set forth at 5 Tr 1564-1566.
[27] Mr. Krause's testimony is transcribed at 5 Tr 1483-1489; his qualifications are set forth at 5 Tr 1484-1486.

DTE's request to exceed the 10% amount is denied, the company could renew its request in this case.

Codie S. Matthews, Public Utilities Engineer in the Smart Grid Section of the MPSC's Operations and Wholesale Markets Division, testified regarding the company's request for recovery of Advanced Metering Infrastructure (AMI), demand response, IT, and cyber-security expenditures.[28] He testified that Staff generally considers the company's projected test year capital and O&M expenditures reasonable and prudent, but recommends that the company provide annual smart grid reporting metrics as identified in Schedule 10.0 of his Exhibit S-10. Mr. Matthews testified that Staff generally supports DTE's projected demand response efforts but recommends a cautious approach until appropriate metrics are developed. He recommended a reduction of $5.6 million to the company's request for energy bridges, to match expenditures to the number of customers using DTE's mobile application, presenting supporting information in Schedules 10.1 through 10.4 of Exhibit S-10. Mr. Matthews also recommended that the company's programmable communicating thermostat program be limited until DTE establishes that customers are enrolling in the program. Addressing the company's proposed Information Technology (IT) expenditures, Mr. Matthews similarly testified that Staff supports generally supports the company's projected spending, but recommends normalizing adjustments to reflect the variability in expenditures from year to year, also presenting Schedules 10.5 and 10.6 of Exhibit S-10.

[28] Mr. Matthews's testimony, including his rebuttal, is transcribed at 5 Tr 1491-1506; his qualifications are set forth at 5 Tr 1492-1493.

Donald J. Mazuchowski is the Electric Operations Manager for the MPSC. He presented Staff's recommended adjustments to DTE's proposed distribution system capital expenditures.[29] He reviewed DTE's expenditures in 2015 compared to the company's projected spending in Case No. U-17767, and testified that Staff does not believe the company will be able to spend the full increase in spending it is proposing for the projected test year in this case. He acknowledged that DTE's system reliability needs improvement and recommended a 10% annual increase in the level of capital expenditures from 2015 through the projected test year. He presented two schedules in Exhibit S-9, Schedules 9.3 and 9.5, to show DTE's recent capital spending levels in comparison to Staff's recommendation and to show DTE's capital spending levels in comparison to several other utilities. Mr. Mazuchowski also testified that Staff does not support DTE's request to treat certain tree-trimming expenses as a regulatory asset.

Brian Welke, an auditor in the financial Analysis and Audit Division of the MPSC's Revenue Requirements Section, presented Staff's recommended O&M expense allowance of $1,262,978,000 for the projected test year, as shown in his Schedule C5 of Exhibit S-3.[30] His Schedule C5 also shows the adjustments responsible for the $69.3 million difference between Staff's projection and DTE's request identifying the sponsoring Staff witness or supporting schedule. Mr. Welke testified in support of several of Staff's adjustments including a revised inflation estimate, incentive compensation, uncollectible accounts expense, injuries and damages, property insurance, pensions and benefits, accrued vacation, and Supplemental Retirement Plan (SRP) expenses. Regarding Staff's inflation estimate, he testified that Staff used a 2015

[29] Mr. Mazuchowski's testimony is transcribed at 5 Tr 1508-1517; his qualifications are set forth at 1509-1511.
[30] Mr. Welke's testimony is transcribed at 5 Tr 1571-1583; his qualifications are set forth at 5 Tr 1572.

historical test year as the basis for its O&M expense projections, rather than 2014 as DTE used, and used the inflation factors recommended by Mr. Megginson. Regarding incentive compensation expense, Mr. Welke testified that Staff has excluded the portion of the incentive compensation expenses requested by DTE that are related to financial metrics to be consistent with the Commission's decision in Case No. U-17767. Regarding uncollectible expense, he testified that Staff's adjustment is based on the use of more recent information and incorporates a portion of the proceeds from the company's debt sale in 2008. Regarding injuries and damages expense, Mr. Welke testified that Staff's adjustment is based on the use of more recent data. Regarding property insurance expense, he testified that Staff rejected DTE's use of a five-year average and used the historical test-year expense adjusted for inflation, consistent with prior Commission orders. Regarding pension and benefits expense, Mr. Welke testified that Staff's adjustment is attributable to the use of more recent data and Staff's inflation factors. Regarding accrued vacation expense, he testified that Staff's adjustment used a four-year average to minimize the impact of an inconsistent 2014 expense level. Regarding the SRP expenses, he testified that Staff removed the company's projected expenses consistent with past case.

Mr. Welke also testified regarding the company's request for rate base treatment of the unamortized balance of its COL expenses, recommending that the Commission defer recovery of a return on the COL expenses until the company makes a "build" or "no-build" decision. And, Mr. Welke explained Staff's rejection of the company's request for regulatory asset treatment of certain tree-trimming expenditures. Finally, Mr. Welke explained Staff's adjustment to the company's property and other tax expense projection to better reflect historical experience.

Jing Shi, Public Utilities Engineer in the Act 304 and Sales Forecasting Section of the Commission's Regulated Energy Division, addressed DTE's projected production plant O&M expenses including the steam production, fuel supply and MERC, nuclear, hydroelectric, and other expense categories.[31] She testified that Staff revised DTE's projections to reflect Staff's inflation rates supported by witness Megginson and shown in her Schedule 8.1 of Exhibit S-8. She testified that Staff also adjusted the O&M projection for the River Rouge Unit 2 as shown in her Schedule 8.2 of Exhibit S-8 to reflect the planned retirement of this unit. Regarding nuclear expense projections, Ms. Shi testified that Staff adjusted DTE's projections for "Program Evaluation and Review Committee" (PERC) projects to reflect a normalization of expenses over a ten-year period, as shown in Schedule 8.3 of her Exhibit S-8. Ms. Shi testified that Staff's adjustments reduce DTE's projected production O&M expenses by $39,100,000.

Peter J. Derkos, Public Utilities Engineer Specialist in the Electric Operations Section of the MPSC's Operations and Wholesale Marketing Division, presented Staff's recommended O&M expense level for DTE's test year distribution operations.[32] He testified that Staff is recommending that distribution O&M expenses for the test year be based on a five-year average of historical spending levels with adjustments for inflation, storm restoration, preventative maintenance and tree trimming. Mr. Derkos's Schedule 9.0 of Exhibit S-9 shows total distribution O&M expenditures from 2011 to 2015, with additional supporting detail in Schedules 9.1 through 9.4 of that exhibit. He testified that

[31] Ms. Shi's testimony is transcribed at 5 Tr 1543-1549; her qualifications are set forth at 5 Tr 1544-1545.
[32] Mr. Derkos's testimony is transcribed at 5 Tr 1455-1468; his qualifications are set forth at 5 Tr 1456-1459.

he eliminated expenses recovered through the Transitional Reconciliation Mechanism before applying Staff's inflation values. He testified that he further adjusted the five-year average by adding an additional amount for tree trimming, including a savings estimate to reflect expected reductions in restoration costs and adopted DTE's requested adjustment for preventive maintenance of station equipment and underground lines. Mr. Derkos also testified regarding Staff's opposition to regulatory asset treatment for tree-trimming expenses.

Kurt D. Megginson, Financial Specialist in the Revenue Requirements Section of the Commission's Financial Analysis and Audit Division, presented testimony addressing the cost of capital and the rate of inflation.[33] Mr. Megginson's Schedule D1 of Exhibit S-4 is a summary of Staff's recommended overall rate of return of 5.52%, based on a cost of equity capital of 10%, and the 50-50 capital structure and other cost elements used by DTE. In determining the cost of equity capital, Mr. Megginson performed several analyses of the cost of capital for a proxy group of companies including a discounted cash flow study, a Capital Assets Pricing Model study, and a risk premium analysis. The results of these analysis are presented in his Schedule D5. He also considered other recent state commission return on equity awards and the company's currently-authorized rate of return. Mr. Megginson also provided a forecast of inflation factors for 2016 and 2017 of 1.45% and 2.57% respectively, as shown in his Schedule D3 of Exhibit S-4.

[33] Mr. Megginson's testimony, including cross-examination, is transcribed at 5 Tr 1379-1453; his qualifications are set forth at 5 Tr 1383-1385.

Charles E. Putnam is a Departmental Analyst in the Rates and Tariffs Section of the MPSC's Regulated Energy Division.[34] He performed Staff's cost of service study and testified regarding the results, also presented in his Schedule F1 of Exhibit S-6. He testified that Staff made essentially four changes to DTE's cost of service study: changing the weighting of the production cost allocator from 4CP 100 to 4CP 75-0-25, making a corresponding change in the 200B allocator, revising the inputs to DTE's calculation of the monthly customer charge, and changing the allocation of uncollectible accounts expense from historic net write-offs to total cost to serve.

Deanne B. Rivera is also a Departmental Analyst in the Rates and Tariffs Section of the MPSC's Regulated Energy.[35] She presented Staff's recommendations regarding residential rate design testifying that Staff recommends a monthly customer charge of $7.50, supports DTE's proposed 20% cap for variable distribution rates with the residential secondary rate schedules, recommends reducing the number of customers expected to participate in the Residential Income Assistance (RIA) program, and proposes setting the Senior Citizen credit at 50% of the RIA credit.

Regarding the lighting tariffs, Ms. Rivera testified that Staff supports the company's proposal to revise the existing financing charge option as an alternative to a contribution in aid of construction, but further recommends that the tariff explicitly include the final weighted average cost of capital approved in this case, and explicitly make the financing charge option available to all lighting customer conversions as well as new business. She also encouraged the company to explore an option to allow

[34] Mr. Putnam's testimony, including cross-examination, is transcribed at 5 Tr 1334-1359; his qualifications are set forth at 5 Tr 1338-1340.

[35] Ms. Rivera's testimony is transcribed at 5 Tr 1532-1541; her qualifications are set forth at 5 Tr 1533-1536.

customers converting to LED lights to pay third-party financing costs through their DTE bills. Ms. Rivera also supported other lighting tariff changes proposed by DTE, except for the proposed elimination of the de-energized and dusk-to-midnight lighting provisions which she recommended be retained as a cost-saving alternative for customers. Ms. Rivera recommended that the structure of charges in the lighting tariffs be broken into component per-luminaire and per-kWh (power supply) charges with the total per light monthly charges also stated. She also recommended further refinements in future cases. Noting that Mr. Revere presented Staff's rate design for the lighting tariffs, she testified that DTE should take steps to mitigate the impact of lighting rate increases for municipalities including the encouragement and prioritization of LED conversions. Ms. Rivera also endorsed DTE's calculation of miscellaneous revenue.

David W. Isakson, a Departmental Analyst in the Rates and Tariffs Section of the MPSC's Regulated Energy Division, presented Staff's recommendations regarding secondary and primary rate design.[36] He testified that Staff's commercial secondary distribution rates were calculated using the same method approved in Case No. U-17767, with a proposed increase in the monthly service charge to $11.25, based on Mr. Putnam's analysis. He testified that Staff's primary distribution rates by voltage class were also determined using the same method approved in Case No. U-17767. For the power supply rate design for commercial and primary customers, Mr. Isakson testified that Staff used the same method as DTE but using Staff's revenue requirement. Additionally, Mr. Isakson addressed DTE's contingent request for a Revenue Decoupling Mechanism, recommending that the Commission reject DTE's request. He

[36] Mr. Isakson's testimony, including rebuttal and cross-examination, is transcribed at 5 Tr 1280-1333; his qualifications are set forth at 5 Tr 1284-1285.

testified that the Commission should wait until any new legislation is passed to consider an RDM and further testified that Staff does not believe the company's proposed RDM would lead to just and reasonable rates. He identified the conditions under which he believes an RDM would result in just and reasonable rates and explained Staff's alternative proposal.

Nicholas M. Revere, Manager of the Rates and Tariffs Section of the MPSC's Regulated Energy Division, presented Staff's recommended rate design for the lighting tariffs.[37] He referred to discussions held during the collaborative resulting from Case No. U-17767 in explaining that Staff recommends moving lighting rates to the cost of service by lighting type based on the results of DTE's updated model. He testified that the move to cost-based rates for LED lighting should be the most important priority, and also that rate increases for any lighting category should be capped so that no customer has an impact of more than 3 times the overall lighting increase. Staff's resulting rate design is included in his portion of Schedule F3 of Staff's Exhibit S-6.

C. Attorney General

The Attorney General presented the testimony of Sebastian Coppola, independent consultant and President of Corporate Analytics, Inc., accompanied by Exhibits AG-1 through AG-36.[38] Mr. Coppola calculated a revenue deficiency for DTE of $109.5 million, presented in his Exhibit AG-36, based on decreased capital and O&M expense spending projections, an increased revenue projection, and an authorized return on equity of 9.75%.

[37] Mr. Revere's testimony, including cross-examination, is transcribed at 5 Tr 1360-1377; his qualifications are set forth at 5 Tr 1363-1364.
[38] Mr. Coppola's testimony is transcribed at 6 Tr 1769-1872; his qualifications are set forth at 6 Tr 1771-1774 and 5 Tr 1862-1872.

Mr. Coppola recommended that "contingency" capital spending of $18 million be removed from the rate base projection. Addressing DTE's projected $1.3 billion in capital spending for distribution operations from the historical test year through the projected test year, he recommended excluding DTE's projected $41.8 million in spending for the Gordie Howe International Bridge, excluding $10.5 million in proposed spending for a SCADA monitoring system, and excluding $13.4 million projected for distribution system upgrades associated with bridge work on the I-75 highway. He also recommended that the Commission reject DTE's request to establish a regulatory asset to recover certain vegetation management expenses incurred through 2015 and projected through July 2017.

Addressing DTE's projected $1.2 billion in capital spending for fossil generation, he recommended a reduction of $12.1 million for projected routine capital expenditures based on a review of historical expenditures and an additional reduction of $13.2 million for DTE's projected expenditures in preparation for potential construction of one or more natural-gas-fired generating plants. Turning to DTE's projected $33.2 million capital expenditures for additional renewable energy and demand-side management, Mr. Coppola recommended excluding the projected $13 million renewable energy expenditures from rate base, disputing that the projected expenditures were sufficiently likely to occur. He also recommended excluding $2.5 million for a pilot program for Distributed Customer Generation (DCG) that he characterized as uncertain, and $9.5 million for the DTE Insight and PCT programs. Regarding the DTE Insight program, Mr. Coppola also expressed concern that DTE expenditures would be directed to a company that is a joint venture owned in part by DTE Energy Ventures, a non-utility affiliate of DTE, also citing his Exhibits AG-22 and AG-23.

Mr. Coppola recommended a $24.7 million reduction in DTE's proposed nuclear generation capital expenditures of $625.8 million, characterizing the company's projected routine capital expenditures as out of line with historical levels and premature relative to the fuel cycle. Mr. Coppola also recommended that the Commission reject DTE's request to include the unamortized $96.9 million balance of its COL costs for a potential Fermi 3, citing the Commission's decision in Case No. U-17767.

Turning to DTE's projected capital expenditures for its Corporate Staff Group, Mr. Coppola recommended a $55.5 million reduction to DTE's projected capital expenditures of $536.7 million, based on his conclusion that certain information technology (IT) programs had not been sufficiently justified including a software tool for landlords, certain reliability projects, and Enterprise Software expenditures. He also took issue with projected facilities renovation expenditures, including expenditures for a gym and a clinic, and other renovation expenditures he concluded lacked specificity and support, and he recommended adjustments to capital expenditures for the Grand River Public Space and Federal Park Place to be consistent with the Commission's decision in Case No. U-17767.

Mr. Coppola also recommended that the working capital allowance be reduced by $86.6 million to reflect a lower projected increase in working capital for accrued post-retirement benefits as presented in his Exhibit AG-29, an increased projection of interest payable that he attributes to increased long-term debt balances, an income-tax adjustment to eliminate the impact of tax credits available in the historical test year, and a reduction to exclude DTE's interest-earning investment in the Detroit Investment Fund.

Turning to O&M expense projections, Mr. Coppola recommended a total reduction of $132.3 million to DTE's projected test year O&M expense level of $1.332 billion, as summarized in his Exhibit AG-4. He testified that his recommendation reflects the elimination of all inflationary increases other than employee healthcare to reflect the company's Competitive and Affordable Rate Strategy (CARS) program. Regarding fossil generation expenses, he also recommended a 50% reduction in projected spending for Clean Power Plan (CPP) and Integrated Resource Planning (IRP) activities to reflect the U.S. Supreme Court's stay of the CPP. Regarding electric distribution expenses, he recommended a reduction of $3.9 million in DTE's overhead line expense projection, using an updated five-year average and excluding the amortization DTE requested for certain tree trimming expenses. Regarding customer service and marketing expenses, Mr. Coppola recommended excluding DTE's request for $3 million for economic development activities. Regarding other administrative and general expenses, Mr. Coppola recommended excluding all incentive compensation expense, updating the company's five-year average calculation for property insurance and injuries and damages expense, and excluding an additional $3 million in advertising costs. For pension and benefits expense, Mr. Coppola recommended a $6.2 million reduction to the company's projected increase using alternate inflation factors for employee healthcare that he testified were more consistent with recent experience. Finally, Mr. Coppola recommended an additional $1.1 million reduction in O&M expenses to reflect estimated savings in uncollectible accounts expense, as presented in his Exhibit

AG-10. Mr. Coppola also recommended an increase in the revenue component of the adjusted net income calculation based on his upward adjustment of DTE's residential sales forecast to reflect his analysis of historical data and the impact of energy efficiency options. He presented Exhibits AG-1 through AG-3 to support his testimony.

Mr. Coppola recommended that the Commission calculate an overall rate of return of 5.43%, based on the capital structure and debt costs used by DTE and a return on equity of 9.75% as shown in his Exhibit AG-30. Mr. Coppola also recommended that the Commission reject DTE's proposed contingent RDM.

Regarding the cost allocation methods, Mr. Coppola recommended that the Commission reject DTE's proposal to allocate production costs entirely on the basis of peak demand. Turning to the monthly customer charges proposed by DTE, Mr. Coppola objected to DTE's proposed 50% increase in the monthly customer charge for residential customers, recommending an increase of no more than 25%. He also called for the Commission to require DTE to provide an evaluation in its next rate case of the current 17 KWh/day level used as the threshold for increased power supply charges for residential customers,.

D. <u>MEC/SC/NRDC</u>

The Michigan Environmental Council, the Sierra Club, and the Natural Resources Defense Council (collectively MEC/SC/NRDC) jointly presented the testimony of two witnesses, and NRDC alone presented the testimony of an additional witness.

George E. Sansoucy is an engineer and consultant on public utility and energy issues with his own firm, George E. Sansoucy, P.E., LLC.[39] Mr. Sansoucy testified on

[39] Mr. Sansoucy's testimony is transcribed at 5 Tr 1644-1668; his qualifications are set forth at 5 Tr 1645-1647 and his resume is Exhibit MEC-15.

two issues: the inclusion in revenue requirements of certain costs associated with DTE's River Rouge plant, and DTE's proposed allocation method for production plant. Regarding the Rouge River plant, he testified that because DTE has decided to retire Unit 2, which has been on forced outage since July of 2015, it should reevaluate the economics of continuing to operate Unit 3. Mr. Sansoucy identified the following reasons for concern: common plant costs would now be allocated entirely to Unit 3; capacity prices are currently 18% below the prices DTE used in its most recent analysis; and forecasted market energy prices are 9-12% below the prices used in DTE's most recent analysis. Concluding from his review of DTE's discovery responses that it is not clear what capital and major maintenance expenditures DTE has included in its projected test year revenue requirement, Mr. Sansoucy recommended that the Commission require that all capital and major maintenance expenditures that are not directly related to an expeditious retirement of the whole plant be excluded from the revenue requirement used in this case.

Addressing the production cost allocation method, Mr. Sansoucy objected to DTE's proposed 4CP 100 allocation of production costs. Based on his review of the hourly demand by customer class on peak days as well as the NARUC Utility Cost Allocation Manual, he recommended that the Commission retain the current method or move to the equivalent peaker method to better match rates to the cost of service. Mr. Sansoucy presented Exhibits MEC-16 through MEC-36 in support of his testimony.

Douglas B. Jester is a consultant and a principal of 5 Lakes Energy LLC.[40] He testified on issues involving the revenue requirement, cost allocation, and rate design,

---

[40] Mr. Jester's testimony is transcribed at 5 Tr 1588-1642; his qualifications are set forth at 5 Tr 1589-1591, and in his resume, Exhibit MEC-1.

and had additional recommendations to the Commission. Mr. Jester recommended that the Commission reject DTE's request to recover a return on its COL expenditures. He also recommended that the Commission defer DTE's request to include natural gas plant development expenditures in rate base until it has the opportunity to review a certificate of necessity application or other proceeding regarding the reasonableness and prudence of the utility's plans. Additionally, Mr. Jester recommended that the Commission condition approval of distribution capital spending on DTE's preparation of a reasonable system loss mitigation plan, taking advantage of the AMI capabilities. He described actions undertaken by several other utilities.

Addressing cost allocation issues, Mr. Jester reviewed DTE's fixed monthly customer charges for residential customers and recommended that the Commission reject DTE's method for determining the level of these charges, citing the Commission's decision in Case No. U-17767. He testified that fixed charges above the marginal cost of customer connection and service are not just and reasonable and adversely affect low-income customers and the general public interest in efficient use of energy.

Mr. Jester also reviewed DTE's proposals and prior Commission orders involving time-of-use rates. He testified that DTE did not comply with the Commission's direction to offer time-of-use rates to all customers who have had an AMI meter for at least a year, failing to provide for time-of-use rates for all such commercial and industrial customers. He further recommended that the Commission approve DTE's request for funding for its programmable thermostat program, make Rate Schedule D1.8 the default schedule for all new residential and secondary commercial customers with a counterpart for industrial customers, and require notice via bill inserts to customers as they become eligible for the time-of-use rate. Mr. Jester also presented Exhibits MEC-2 through MEC-14 in support of his testimony.

NRDC alone presented the direct testimony of Dylan Sullivan, a Senior Scientist for the NRDC.[41] Mr. Sullivan testified regarding DTE's proposed RDM recommending that the Commission not approve the proposed mechanism. While he testified that decoupling removes a utility's disincentive to support all forms of energy efficiency, he characterized the company's proposal as a lost revenue adjustment mechanism and "an inferior alternative". He recommended that if the Commission acquires the authority to adopt an RDM, it should instead implement a "Symmetrical Revenue Decoupling Mechanism" that would allow DTE to collect exactly the revenue requirement adopted by the Commission in this case with the option to allow for a variation based on a change in the number of customers, and the option to allow for a variation based on inflation. He also recommended a limit of 3% on the size of any adjustment. Mr. Sullivan presented Exhibits NRDC-2 through NRDC-4 in support of his testimony.

E. ABATE

ABATE presented the direct testimony of two witnesses. Michael P. Gorman is a consultant on public utility regulatory issues and Managing Principal for the firm Brubaker & Associates, Inc.[42] Mr. Gorman presented his recommendation that the authorized return on equity be set at 9.2%, with a critique of the analysis underlying DTE's requested return on equity of 10.5%. Mr. Gorman testified that DTE's authorized returns on equity have been substantially higher than industry averages over the last

[41] Mr. Sullivan's testimony is transcribed at 5 Tr 1670-1679; his qualifications are set forth at 5 Tr 1671-1672 and in Mr. Sullivan's resume, Exhibit NRDC-1.
[42] Mr. Gorman's testimony is transcribed at 6 Tr 1876-1954; his qualifications are set forth at 6 Tr 1878 and 6 Tr 1941-1944.

three rate cases, while DTE's credit rating is no stronger and its cost of capital is no lower than peer companies, with the result instead that DTE's ability to provide Michigan customers with competitive utility services has been eroded relative to its regional peers. Mr. Gorman explained his analyses beginning with a review of the market's assessment of utility industry risk, credit standing, and stock prices, as well as industry authorized returns. Mr. Gorman then explained the Discounted Cash Flow, risk premium, and Capital Asset Pricing Model analyses he performed including his choice of proxy companies. He also compared key credit rating financial ratios for DTE, estimated using his recommended return on equity and DTE's actual capital structure, to S&P's benchmark financial ratios. From this analysis he concluded that his recommended overall rate of return supports DTE's investment-grade bond rating. Mr. Gorman presented Exhibits AB-1 through AB-19 in support of his testimony.

James R. Dauphinais is a consultant on public utility regulatory issues and Managing Principal with Brubaker & Associates, Inc.[43] Mr. Dauphinais addressed several issues in his testimony. Regarding DTE's revenue requirement, he recommended that the Commission reject DTE's request for a rate of return on the unamortized balance of its COL costs. He also recommended that the Commission reject the company's proposed RDM.

Regarding cost allocations, Mr. Dauphinais testified in support of DTE's proposed allocation of production costs. Mr. Dauphinais also recommended several modifications to DTE's proposed rate design. Regarding DTE's proposed rate design for the Primary Supply Rate D11, Mr. Dauphinais testified that the voltage level discounts should be

[43] Mr. Dauphinais's testimony, including his rebuttal testimony, is transcribed at 6 Tr 1955-2025; his qualifications are set forth at 6 Tr 1957-1958 and 6 Tr 2011-2015.

increased for transmission and subtransmission customers. Regarding Rider 10, Mr. Dauphinais testified that the proposed administrative charges contain O&M costs not incurred by Rider 10 customers. And regarding Rider 3, Mr. Dauphinais recommended reinstating a modified market power supply pricing option. For customers not taking service under this market power supply pricing option, Mr. Dauphinais also testified that the monthly reservation and on-peak daily demand charges should be reduced to avoid subsidization and to be consistent with PURPA rules for backup and maintenance power. Finally, Mr. Dauphinais recommended revised language for DTE's Rider EC2 to limit the utility's control over a determination of the incremental load that must be considered "full service" load for customers currently taking choice service, and to provide a mechanism to resolve metering issues. He testified that his recommendations are consistent with the Commission's decision in Case No. U-15801. Mr. Dauphinais presented Exhibits AB-20 through AB-25 in support of his testimony.

Mr. Gorman and Mr. Dauphinais also presented rebuttal testimony as discussed below.

F. Walmart

Walmart presented the testimony of Gregory W. Tillman, Senior Manager for Energy Regulatory Analysis for Wal-Mart Stores, Inc., with 4 exhibits.[44] He identified $969 million of Construction Work in Progress (CWIP) in rate base. He recommended that the Commission exclude CWIP from rate base, characterizing it as a shift of risk from investors to ratepayers, and presenting additional information in Exhibit GWT-3.

[44] Mr. Tillman's testimony is transcribed at 6 Tr 1727-1745; his qualifications are set forth at 6 Tr 1729-1730 and in his resume, Exhibit GTW-1.

He also recommended that the Commission reject DTE's proposed RDM for commercial and industrial customers, even if the legislature authorizes the Commission to adopt an RDM, further proposing modifications. Testifying to the importance of keeping rates at an affordable level, Mr. Tillman recommended that the Commission closely examine the revenue requirement and rate of return issues identifying the inclusion of CWIP, the use of a future test year, and other risk-reducing factors that should be considered in setting a return on equity. Mr. Tillman presented information regarding returns on equity set by other regulatory commissions nationwide, citing his Exhibit GWT-4, and characterizing DTE's requested rate of return of 10.5% as above the average for 2013 through the first half of 2016. He also testified that he supports DTE's cost of service study and rate design for the Rate D11 tariff.

G. Kroger

Kroger presented the testimony of its consultant, Neil Townsend, Principal at Energy Strategies, LLC, and 3 exhibits.[45] Addressing the revenue requirements for DTE, Mr. Townsend recommended that the Commission remove inflation from DTE's projected non-labor O&M expenses to avoid reinforcing cost increases, likening the inflation factors to a "cost cushion". He testified that this results in a $38 million reduction to O&M expense as shown in his Exhibit KC-1. Mr. Townsend also recommended that the Commission reject DTE's proposed RDM.

Mr. Townsend also testified extensively regarding cost of service and rate design issues. He testified that he supports DTE's proposed production cost allocation method using only a peak-demand allocator measured by four coincident peaks. Regarding

[45] Mr. Townsend's testimony is transcribed at 3 Tr 50-79; his qualifications are set forth at 3 Tr 51-52 and 3 Tr 69-79.

DTE's proposed Rate D11 primary-voltage-level distribution charge however, Mr. Townsend testified that he does not support DTE's proposed monthly service charge. He testified that the DTE should limit the monthly customer charge to costs that vary directly according to the number of customers with the remaining revenue recovered through the delivery demand charge. Citing the Commission's decision in Case No. U-17767 as rejecting DTE's method, Mr. Townsend testified that the monthly customer charge for the primary-voltage-level customers should not exceed $121.

H. Energy Michigan

Energy Michigan presented the testimony of independent consultant Alexander J. Zakem, whose office is in Plymouth Michigan, and 3 exhibits.[46] Mr. Zakem testified to identify and explain DTE proposals affecting choice customers. Mr. Zakem first testified regarding DTE's proposed RDM, not objecting to the concept of an RDM, but identifying several deficiencies he perceives in the utility's proposal in the absence of authorizing legislation. He recommended that the Commission defer approval of an RDM to a future proceeding. Mr. Zakem also addressed the MISO capacity market focusing on DTE's reference to projected shortfalls. He testified that MISO's most recent report shows a reserve margin deficit of only 0.3 GW, a 1 GW improvement since the 2015 report, and he testified that additional generation of approximately 3 GW under development in Zone 7 is not included in the MISO totals. He presented Exhibit EM-2 in support of his testimony.

Mr. Zakem addressed DTE's request for funds for economic development activities, objecting to the request in concept, and also arguing that any such costs

[46] Mr. Zakem's testimony is transcribed at 6 Tr 1694-1724; his qualifications are set forth at 6 Tr 1695-1696 and in his resume, Exhibit EM-1.

should be allocated separately to power supply and distribution components. Mr. Zakem also recommended that the Commission reject DTE's proposal to recover incentive compensation expenses, particularly focusing on the financial metrics, and further recommending that choice customers should pay only for performance improvements to the distribution system.

Finally, Mr. Zakem addressed DTE's proposed tariff revision for the Retail Access Service Rider EC2. He recommended alternative language to provide additional clarification.

I. Residential Customer Group

The RCG presented the testimony of Geoffrey C. Crandall and 6 exhibits. Mr. Crandall testified regarding the rates, charges, and tariff provisions applicable to the company's AMI program, and to offer policy recommendations.[47] He testified specifically regarding the opt-out charges for customers who do not want a transmitting AMI meter. He objected to DTE's calculated increase in the one-time assessment to $69.70 and increase in the monthly fee to $10.63, testifying that DTE has not provided an adequate basis in its filing to demonstrate the reasonableness of the opt-out charges. Mr. Crandall reviewed information presented by DTE regarding the savings from the AMI program and the number of customers choosing to opt out and emphasized the magnitude of customer opposition to the company's program. He recommended that the Commission require a review updated analysis of the cost elements that were used to set the original charges as well as a prudency review. Mr. Crandall recommended that the opt-out charges be set at $0, citing the AMI cost

[47] Mr. Crandall's testimony is transcribed at 6 Tr 1750-1766; his qualifications are set forth at 6 Tr 1751-1752 and in his resume, Exhibit RCG-1.

savings to support his conclusion that there is no compelling economic reason to continue to assess the special fees. Mr. Crandall also addressed certain elements of DTE's implementation of its AMI meter program contending that DTE's procedures should include clear notice and customer consent. He also offered as an alternative to the $0 charge that charges would be eliminated for those customers who choose to read their own meters. He reviewed AMI implementations from other states and Mr. Crandall recommended a revision to a tariff provision addressing DTE access to customer premises that he characterized as inappropriate and lacking in adequate customer protections, presenting his proposed revision in Exhibit RCG-3.

Mr. Crandall also addressed an amortization expense included in DTE's case testifying that DTE should not recover costs associated with taxes paid to the City of Detroit in years prior to the projected test year, although he acknowledged that the Commission approved this treatment in Case No. U-17767.

J. Rebuttal

DTE, Staff, and ABATE presented rebuttal testimony. DTE witnesses provided rebuttal testimony addressing the rate base, rate of return, adjusted net operating income, accounting, and rate design. Regarding rate base, Mr. Warren addressed the non-nuclear generating plant issues, presenting Exhibit A-31 as a rebuttal exhibit. Mr. Colonnello provided rebuttal testimony addressing Mr. Coppola's recommended nuclear capital expense reductions, presenting Exhibit A-27. Ms. Dimitry provided rebuttal addressing renewable energy capital expenditures, energy bridges, and the Fermi 3 Combined Operating License expenses. She presented Exhibit A-29. Mr. Whitman testified in support of DTE's proposed capital spending for distribution operations addressing recommendations made by Mr. Mazuchowski, Mr. Coppola, and Mr. Jester. He presented Exhibit A-28. Ms. Uzenski's rebuttal addressed recommendations regarding projected capital expenses for Information Technology and for facilities expenses within the Corporate Support Group and regarding the company's requested regulatory asset treatment for certain tree-trimming expenses. Ms. Uzenski also addressed Mr. Coppola's recommended adjustment to the balance of accrued Other Post Retirement Benefits (OPEB) in working capital, Mr. Tillman's recommendation to exclude CWIP from rate base, and Mr. Coppola's calculation of a revised rate base incorporating his recommended adjustments.

Dr. Vilbert provided rebuttal testimony regarding the authorized return on equity, addressing the methods and inputs used by the other analysts, and responding to certain critiques of his analysis. He also presented Exhibit A-34.

Turning to adjusted net operating income, Mr. Leuker provided rebuttal testimony regarding the revenue forecast in response to Mr. Coppola's recommended adjustment and regarding the use of inflation in response to Mr. Townsend's recommendations. He presented Exhibit A-26. Mr. Whitman's rebuttal testimony also addressed DTE's distribution operations expense projections in response to Mr. Derkos's and Mr. Coppola's recommendations. Ms. Uzenksi's rebuttal testimony also addressed the use of inflation, adjustments to advertising and property insurance expenses recommended by the Attorney General and Staff witnesses, and the normalization of PERC expenses proposed by Staff witness Ms. Shi. Mr. Colonnello's rebuttal testimony also addressed Ms. Shi's recommendation to normalize these expenses. Ms. Uzenski presented Exhibit A-30 in support of her rebuttal testimony on capital and O&M

expenses. Mr. Wuepper's rebuttal testimony focused on Staff, the Attorney General, and Energy Michigan recommendations regarding DTE's incentive compensation expenses. He presented Exhibit A-32. Mr. Heaphy provided rebuttal testimony addressing Staff's recommended adjustment to property tax and addressing Mr. Crandall's recommendation regarding the Detroit municipal tax rate change. His rebuttal exhibit is Exhibit A-31. Mr. Sitkauskas also provided rebuttal testimony addressing Staff's recommended reporting metrics for AMI and addressing Mr. Crandall's testimony regarding DTE's tariff.

Regarding rate design, Mr. Johnston testified in rebuttal to Mr. Revere identifying three changes to his recommendations regarding lighting rate design and presenting Exhibit A-35. Mr. Lacey addressed criticisms of the cost study that formed the basis for DTE's proposed monthly customer charges in his rebuttal. He addressed Mr. Putnam's testimony regarding the allocation of uncollectible expense and Mr. Zakem's testimony regarding incentive expense. He also presented Exhibit A-36. Mr. Bloch's rebuttal testimony addressed Mr. Dauphinais's and Mr. Townsend's testimony regarding Rate D11, Mr. Zakem's testimony regarding Rate EC2, and Mr. Jester's testimony recommended time-of-use rate offerings to commercial and industrial primary, subtransmission, and transmission customers.

Staff presented the rebuttal testimony of three witnesses. Mr. Matthews presented rebuttal testimony in response to Mr. Coppola's recommendations regarding DTE's demand-side management capital expense projection. Mr. Isakson's rebuttal testimony addressed Mr. Dauphinais's recommendations regarding voltage level discounts for Rate D11, the RCG's testimony regarding opt-out rates for AMI, and

MEC/SC/NRDC's testimony regarding Rate D1.8 (Residential Dynamic Peak Pricing). Mr. Revere's rebuttal testimony addressed Mr. Dauphinais' recommendations regarding Rider 3.

ABATE presented the rebuttal testimony of two witnesses. Mr. Dauphinais provided rebuttal testimony to Staff regarding its rate design recommendations for Rate D11, along with Exhibit AB-26, and Mr. Gorman provided rebuttal testimony to Staff, taking issue with Staff's recommended rate of return on equity.

K. Overview

The parties generally take positions consistent with the recommendations of their witnesses. As noted above, in its brief and reply brief, DTE adopts certain adjustments resulting in a reduced revenue requirement calculation. In their briefs, the Attorney General and MEC/SC/NRDC also adopt certain recommendations made by Staff. The Detroit Public Schools did not make an evidentiary presentation, but in their brief, review the history or rate increases for educational institutions arguing that "radical swings" in costs and cost allocations to Rates D3.2 and D6.2 have not been supported on the evidentiary record. They argue that the Commission should grant only the lowest revenue deficiency supported by the evidence and thus should not increase these rates more than the average increase for the secondary and primary rate classes.

The positions of the parties are discussed in greater detail below. Section III below addresses the legal standards applicable to this case. Section IV discusses choice of test year to be used in setting rates. Section V addresses the rate base, including the appropriate net plant and working capital amounts. Section VI addresses the rate of return, including the appropriate capital structure to use in setting rates and the individual cost elements to use in determining the overall cost of capital. Section VII addresses the test year adjusted net operating income including the sales and revenue projections and the O&M and other expense projections. Section VIII discusses other revenue requirements-related issues. Section IX summarizes the revenue requirement analysis. Section X addresses the cost of service studies and cost allocation issues raised by the parties. Section XI addresses rate design.

The testimony of each of the witnesses and the arguments of the parties are discussed in more detail below, in conjunction with the positions of the parties.

III.

LEGAL STANDARDS

Before addressing the disputes among the parties regarding revenue requirements, cost allocation, rate design, and other matters, it is appropriate to review certain legal issues. It is axiomatic that the Commission is required to set rates that are just and reasonable. Ratemaking is essentially a legislative function, and the Commission is not bound by any particular method or formula in exercising this legislative function. The Commission is required to balance the interests of the public utility and the consuming public.

DTE begins its brief with a discussion of the legal standards applicable to rate cases. Most of DTE's argument is not controversial. Addressing the burden of proof, however, DTE contends that the Commission should apply what has been labeled as the "substantial evidence" test:

> The Michigan Constitution requires the Commission's findings to "be supported by competent, material and substantial evidence on the whole record." Const 1963, Art 6, § 28. Expert testimony is "substantial" only if it

> is offered by a qualified expert who has an informed and rational basis for his or her view, even if other experts disagree. *Great Lakes Steel v Public Service Comm*, 130 Mich App 470, 481; 334 NW2d 321 (1983). Therefore, substantial evidence is evidence "that a reasoning mind would accept as sufficient to support a conclusion." *Monroe v State Employees' Retirement Sys*, 293 Mich App 594, 607; 809 NW2d 453 (2011). However, "substantial evidence is 'more than a mere scintilla' but less than a 'preponderance' of the evidence." *Huron Behavioral Health v Dep't of Behavioral Health*, 293 Mich App 491, 497; 813 NW2d 763 (2011). *Thus, the applicable standard of proof for purposes of determining whether the Company's proposals or recommendations are reasonable and prudent is the "substantial evidence" standard, which is a lighter standard than even the "preponderance of the evidence" standard, which itself is a lighter standard than the "beyond a reasonable doubt" standard that is only applicable to criminal proceedings*. For the reasons discussed below, DTE Electric's proposals and recommendations in this case more than satisfy the "substantial evidence" standard as demonstrated by the record.[48]

The Attorney General takes issue with DTE's claim that it should prevail if it presents "substantial evidence" in support of its recommendations, rather than expecting the Commission to weigh the evidence and find facts in accordance with the preponderance of the evidence. In his reply brief, the Attorney General argues:

> As noted in the Attorney General's Initial Brief, DTE bears the burden of proof to demonstrate that its rate increase request is reasonable. The obligation of proving any fact lies upon the party who substantially asserts the affirmative of the issue. A plaintiff always has the burden of proving its cause of action. In administrative cases, a party seeking relief must prove his, her, or its claim by a preponderance of the evidence. Likewise, in MPSC Cases, a utility has the burden of proof by a preponderance of the evidence. Moreover, the MPSC may disbelieve even uncontradicted evidence. When the burden of proving a fact falls on one party, then the other party does not have the burden of proving the opposite fact. This is further supported by our Supreme Court which recently explained that an administrative agency's findings of fact are similar to a trial court's findings of fact which similarly uses a preponderance of evidence standard. See *SBC Mich v PSC (In re Complaint of Rovas),* 482 Mich 90, 100-101 (2008).
>
> Accordingly, DTE's claim that it only needs to provide a scintilla of evidence to support its rate increase request is inaccurate. (DTE Initial Brief, pp 11-12.) Although the standard of review on appeal for a

[48] See DTE brief, pages 11-12 (footnotes omitted, emphasis added).

> Commission decision is competent, material, and substantial evidence on the whole record, that is not the burden of proof standard for DTE in order to support its $345 million rate increase request. Interestingly, DTE argues for a scintilla of evidence for its own proposals but appears to argue for a higher burden of proof for intervenors that challenge DTE's proposals. (DTE Initial Brief, pp 11-12.) It is, however, entirely appropriate for an intervenor to argue that DTE has not presented sufficient evidence to support its burden of proof for a project as wells as for the Commission to find that DTE has not presented sufficient proofs for some project or proposal. See *In matter of the application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief*, June 7, 2012 MPSC Order, U-16794 p 13 (stating that "if the utility realistically expects inclusion of the total projected costs, it must supply the Commission with enough evidence to support a finding that the costs are just and reasonable – in the absence of thorough, detailed, and meaningful evidence, the Commission's hands are tied.")[49]

The Attorney General's analysis on this issue is correct. The "substantial evidence" test is actually a standard of judicial review and not the standard the Commission must apply in making findings of fact. Instead, in making findings of fact, the Commission must weigh conflicting evidence and determine what is true by a "preponderance" of the evidence. That is, the Commission must apply what has been labeled the "preponderance" standard. If the Commission does this, then reviewing courts will not substitute their judgment for the Commission's judgment, but will defer to the Commission's findings of fact if those findings are supported by "substantial evidence." The judicial review for "substantial evidence" is a called a deferential standard of review because the reviewing court does not itself weigh conflicting evidence, and has explained that a finding of fact by the Commission will be upheld if it is supported by any competent evidence that is "more than a scintilla".

[49] See Attorney General reply brief, pages 1-2.

This distinction has been explained in many judicial decisions. For example, in *Antrim Resources v Public Service Commission*, the Court explained the distinction between the standard of judicial review and the Commission's obligation to make determinations based on a preponderance standard as follows:

> The standard of judicial review of a decision of the PSC is whether that decision is lawful and supported by competent, material and substantial evidence on the whole record. Const. 1963, art. 6, § 28. *It is for the PSC to weigh conflicting opinion testimony of the qualified ("competent") experts to determine how the evidence preponderated.*[50]

The Commission has also long recognized that the party with the burden of proof must meet the preponderance-of-the-evidence standard. In its March 11, 1986 order addressing a complaint filed by the Association of Businesses Advocating Tariff Equity (ABATE) challenging a proposed refund of pipeline credits, the Commission explained:

> [As] the complainant, ABATE bears the burden of proof and unless it prevails the status quo will continue in effect, just as a plaintiff in a court cannot demand a judgment in its favor merely because it puts in some evidence and the defendant remains silent. The burden of proof requirement. The plaintiff's, and ABATE's evidence must persuade by a preponderance of the evidence.[51]

It is understandable that persons or parties not familiar with the basic principles of administrative law would find this distinction confusing. But because it is fundamental to an appreciation of the different roles of the Commission and reviewing courts, and because DTE has advanced this same argument in other proceedings, this PFD

[50] See *Antrim Resources v Public Service Commission*, 179 Mich App 603, 620-621 (1989) (emphasis added). Also see, *Department of Community Health v Anderson*, 299 Mich App 591, 598 (2013) ("Although the agency was required to prove its case by a preponderance of the evidence in the proceedings below. . . appellate review does not entail a determination de novo whether this standard was satisfied.")

[51] See, March 11, 1986 order, Case Nos. U-7076 and U-7218, page 4. Also see, e.g., *In the matter of the application of Consumers Power Company for a reconciliation of power supply costs and revenues for calendar year 1988*, September 14, 1990 order, Case No. U-8866-R ("[The] Commission finds that Consumers Energy has proven by a preponderance of the evidence that its failure to discover the defective weld to the steam generator tube plug was not the result of negligence or mismanagement.")

recommends that the Commission take the time and effort to clarify this important distinction. There is no legal presumption that findings of fact should be made in the utility's favor if there is conflicting evidence. If the Commission were to accept DTE's invitation to rule in the utility's favor whenever substantial evidence supports the utility's position, the Commission would not be performing the legally-required weighing and sifting of evidence and would be committing legal error.[52] Instead, as discussed above, the ALJ and the Commission must determine how the evidence preponderates to resolve the disputed issues. Thus, this PFD applies the preponderance of the evidence standard in resolving disputed issues of fact.

In addition, DTE makes some generalized claims regarding its constitutional rights in responding to several arguments raised in this case. For example, in its reply brief, DTE argues it has constitutional protections against "takings" and "confiscatory rates" and "is entitled to rates that provide a corresponding recovery for infrastructure investments that provide safe and reliable service to its customers." [53] DTE then argues that a matter of fundamental ratemaking law, it is entitled to a commensurate return of and on its investment in providing utility service.[54] DTE properly cites *Federal Power Comm v Hope Natural Gas Co*, 320 US 591 (1944) and *Bluefield Waterworks Improvement Co v Public Service Commission of West Virginia*, 262 US 679 (1923) in this context, because these are considered seminal cases in which the Court explained the return that is required, as discussed in section VI below.

In the context in which DTE cites these cases, however, is important to note that the Commission has broad discretion in determining the appropriate amount of

[52] See, e.g., *Aquilina v General Motors Corp*, 403 Mich 206 (1978).
[53] See DTE brief, page 13 at n 28.
[54] See DTE brief, page 14, at n 29.

investment on which a return will be computed. The Michigan Supreme Court has long recognized this principle. In 1920, discussing the authority of the Commission's predecessor agency, the Michigan Railroad Commission, the Court explained:

> On matters involving the exercise of good common sense and judgment only, the determination of the commission must be held to be final unless such determination in its application results in the establishment by 'clear and convincing' proof of a rate so low as to be confiscatory or so high as to be oppressive. What return a public utility shall be entitled to earn upon its invested capital and what items shall be considered as properly going to make up the sum total of that invested capital are questions of fact for the determination of the commission, and their conclusions thereon, upon which the rate is based, are unassailable unless, as a necessary result, it can be affirmatively asserted that the resultant rate is unreasonable and unlawful.
>
> Between the point where a rate may be said to be so low as to be confiscatory and the point where it must be said to be so high as to be oppressive upon the public there is a 'twilight zone' within which the judgment of the commission may operate without judicial interference. Assume that the commission, in determining the amount of the capital invested, allows as an element of the sum an amount which the court, if charged with the initial duty of determination, might find to be excessive or inadequate, or assume that the commission, in the exercise of its best judgment, permitted a rate of return upon the invested capital higher or lower than the court, under like circumstances, might believe to be proper; nevertheless the court would not be warranted in interfering unless the rate, as established, was clearly unreasonable and unlawful.[55]

In the *Hope* case, the United States Supreme Court explicitly held:

> *"[I]t is not theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unreasonable, judicial inquiry ... is at an end. The fact that the method employed to reach that result may contain infirmities is not then important."* [56]

The Supreme Court has more recently affirmed this principle in *Duquesne Light Co v Barasch*, 488 US 299 (1989), holding that a Pennsylvania statute that excluded plant from an electric utility's rate base that was not in use and useful did not result in an

---

[55] See *City of Detroit v Michigan R.R. Comm'n*, 209 Mich 395, 433–34 (1920).
[56] *Fed Power Comm'n v Hope Nat Gas Co*, 320 US 591, 602 (1944)

unconstitutional taking of the utility's property where the overall rate was within constitutional requirements. Similarly, in *Verizon Commc'ns, Inc v FCC,* 535 US 467 (2002), the Court held that the FCC's use of the non-traditional Total Element Long-Run Incremental Cost (TELRIC) method did not raise constitutional concerns. The *Verizon* Court explained:

> At the outset, it is well to understand that the incumbent carriers do not present the portent of a constitutional taking claim in the way that is usual in ratemaking cases. They do not argue that any particular, actual TELRIC rate is "so unjust as to be confiscatory," that is, as threatening an incumbent's "financial integrity." *Duquesne Light Co* [488 US at 307, 312] . . . .
>
> This want of any rate to be reviewed is significant, given that this Court has never considered a taking challenge on a ratesetting methodology without being presented with specific rate orders alleged to be confiscatory. See, *e.g., Duquesne Light Co* [488 US *at* 303–304] (denial of $3.5 million and $15.4 million increases to rate bases of electric utilities); *Smyth v Ames,* [169 US 361, 470–476 (1898)] (Nebraska carrier-rate tariff schedule alleged to effect a taking). Granted, the Court has never strictly held that a utility must have rates in hand before it can claim that the adoption of a new method of setting rates will necessarily produce an unconstitutional taking, but that has been the implication of much the Court has said. See *Hope Natural Gas Co* [320 US 591, 602] ("The fact that the method employed to reach [just and reasonable rates] may contain infirmities is not ... important"); *Natural Gas Pipeline Co* [315 US 575, 586 (1942)] ("The Constitution does not bind rate-making bodies to the service of any single formula or combination of formulas"); [*Los Angeles Gas & Elec Corp v Railroad Comm'n of Cal,* 289 US 287, 305 (1933)] ("[M]indful of its distinctive function in the enforcement of constitutional rights, the Court has refused to be bound by any artificial rule or formula which changed conditions might upset"). Undeniably, then, the general rule is that any question about the constitutionality of ratesetting is raised by rates, not methods.[57]

Thus, in the absence of any issue rising to the level of a constitutional concern, this PFD looks to past Commission decisions addressing various rate case elements for guidance in determining how to resolve disputes among the parties.

[57] *Verizon Commc'ns, Inc v FCC,* 535 US 467, 523–25 (2002).

IV.

TEST YEAR

A test year is used to establish representative levels of revenues, expenses, rate base, and capital structure for use in the rate-setting formula. The parties and the Commission may use different methods in establishing values for these components, provided that the end result is a determination of just and reasonable rates for the company and its customers. DTE filed its rate application using the projected test year August 1, 2016 to July 31, 2017, and its application further indicates that it in presenting projections for this test year, it has used the 2014 historical test year adjusted for known and measurable changes.[58] While some parties dispute various components of the company's projections and rely in part on more recent information, no party proposed using a different projected test year to set rates. Thus, this PFD recommends that the Commission adopt the August 1, 2016 to July 31, 2017 test year, also referred to in this PFD as the 2016-2017 test year.

V.

RATE BASE

Rate base consists of the capital invested in used and useful utility plant, plus the utility's working capital requirements, less accumulated depreciation. DTE presented testimony on its projected capital expenditures broken down into the following categories: non-nuclear production plant (including steam, hydraulic, other, and MERC), nuclear plant (including nuclear fuel), distribution operations, community lighting, corporate staff, automated metering infrastructure (AMI), renewables and demand-side management. Also, the company's filing includes in working capital projected licensing

[58] See DTE's Application, pages 2-3, paragraph 8.

expenses for a potential Fermi 3 nuclear plant to the beginning of the 2016-2017 test year.

The disputes among the parties involve several of the company's projected capital additions for the test year, which are addressed in connection with Net Plant in section A below. Disputes involving the appropriate working capital balance, including disputes regarding the treatment of the Fermi 3 licensing expenses (COL), certain non-qualifying benefit plans, the Detroit Investment Fund, DTE's request for a regulatory asset for certain tree trimming expenses, the treatment of certain obsolete inventory, and other adjustments recommended by the Attorney General, are discussed in section B, while issues related to accumulated depreciation are discussed in section C. In its recent decision setting rates for Upper Peninsula Power Company in Case No. U-17895, the Commission cited a portion of its order from Case No. U-15768 in explaining the utility's obligation to support its rate base projections:

> Section 6a(1) of Act 286, MCL 460.6a(1), provides that a utility "may use projected costs and revenues for a future consecutive 12-month period" to develop its requested rates and charges. As the Commission has discussed previously:
>
> In a case where a utility decides to base its filing on a fully projected test year, the utility bears the burden to substantiate its projections. Given the time constraints under Act 286, all evidence (or sources of evidence) in support of the company's projections should be included in the company's initial filing. If the Staff or intervenors find insufficient support for some of the utility's projections they may endeavor to validate the company's projection through discovery and audit requests. If the utility cannot or will not provide sufficient support for a particular revenue or expense item (particularly for an item that substantially deviates from the historical data) the Staff, intervenors, or the Commission may choose an alternative method for determining the projection.[59]

[59] See September 8, 2016 order in Case No. U-17895, page 4, citing January 11, 2010 order in Case No. U-15768 et al., pages 9-10.

A. Net Plant

Net plant is comprised of total utility plant-in-service, plant held for future use, and construction work in progress (CWIP), less the depreciation reserve. Because Walmart objects to the inclusion of CWIP in rate base and because a discussion of CWIP provides some background for other issues involving net plant, Walmart's arguments are discussed in section 1 below followed by a discussion in sections 2 through 10 of the each of the categories of capital expenditures as presented by DTE in Exhibit A-9, Schedule B6.

1. Construction Work in Progress (CWIP)

Walmart argues that the Commission should no longer include CWIP in rate base. Citing DTE's Exhibit A-9, Schedule B1, Mr. Tillman testified that DTE proposes to include $969 million in CWIP in rate base and explained his objections to this ratemaking treatment:

> Including CWIP in rate base results in charges to ratepayers for assets that are not yet "used and useful in providing electric service. Under the Company's proposal, ratepayers will pay for assets prior to receiving any benefits from those assets. This violates the matching principle (i.e. customers should bear a cost only when they are receiving a corresponding benefit).[60]

He further objected:

> [I]ncluding CWIP in rate base shifts risk onto ratepayers that, traditionally, is assumed by utility investors. Investors are compensated for bearing this risk through the authorization of a return on the investment and the value of financing the construction once the asset is placed in service. Including CWIP in rate base places the risk on the utility's customers who receive no current benefit for the use of their money. Second, if the Company encounters problems during the construction of the plant resulting in stoppage of the construction, non-completion of the project, and/or a substantial delay in the project's completion, ratepayers have no

[60] See 6 Tr 1735.

recourse for recovering or mitigating the cost of financing the asset's construction.[61]

Mr. Tillman estimated the revenue requirement associated with DTE's projected CWIP balance at approximately $90 million. He recommended that the Commission exclude CWIP from rate base, and in the alternative, recommended that the Commission reflect the reduced risk to the company in its authorized return on equity.[62]

Ms. Uzenski provided rebuttal testimony on this topic:

> CWIP is included in this rate filing as required by the Commission's May 10, 1976 Order in Case No. U-4771. Second, CWIP that is not related to environmental projects accrues an Allowance for Funds Used During Construction (AFUDC) based on the Commission authorized return on rate base. (This applies to projects exceeding $50,000 and under construction for at least six months.) The AFUDC included in CWIP is credited to the income statement in both the historical and projected periods. See Exhibit A-10, Schedule C1, line 12. This increase to income is reflected in this case as a reduction to the revenue requirement. Thus, for AFUDC eligible CWIP, other than related to environmental projects, the net revenue requirement is effectively zero.[63]

Dr. Vilbert also provided extensive rebuttal testimony on this topic, characterizing recovery through rate base or through the accumulation of AFUDC as a question of timing:

> CWIP that is not included in rate base earns a return based upon the Allowance for Funds Used During Construction ("AFUDC"). The AFUDC rate is often set at either the allowed cost of capital for the company . . . or at the cost of debt. AFUDC does not result in current cash flow, but is instead added to the CWIP balance. When the investment is completed and placed in service, the accumulated AFUDC is capitalized as part of the cost of investment. In contrast, when CWIP is included in rate base, it earns a current return equal to the regulatory [weighted average cost of capital]; it does not earn AFUDC. This provides the utility current cash flow on an investment not yet in service.[64]

[61] See 6 Tr 1736.
[62] See 6 Tr 1736-1737 and Exhibit GWT-3.
[63] See 4 Tr 868-869.
[64] See 6 Tr 677.

And he explained:

> However, even though the total (undiscounted) dollars paid by customers for capitalized AFUDC are higher, since DTE Electric's AFUDC rate is equal to the regulatory [weighted average cost of capital], the present value of the two streams of payments will be the same, resulting in no net impact to customers.[65]

Dr. Vilbert also identified what he perceived to be benefits from allowing a utility to recover construction work in progress, flowing from the accelerated cash flow, and dismissed Mr. Tillman's concerns to match ratepayer costs for utility plant to the benefits from that utility plant:

> First, it is impossible to match precisely customers' payments for assets and receipt of the services from those assets. The customers of all utilities change over time. Some departing customers will have paid for assets from which they will not receive service, and arriving customers will receive benefits from assets for which they did not pay. However, as noted above, for those customers remaining in the service territory, the present value of the total payments made is identical whether CWIP is in the rate base or not. The timing varies but the present value does not. Second, any issues stemming from an asset that is not completed can be addressed in a subsequent rate proceeding. The possibility that an investment may not be completed is not a reason to deny CWIP in rate base.[66]

In its brief and in its reply brief, DTE cites both Dr. Vilbert's testimony and Ms. Uzenski's testimony.[67]

In its brief, Walmart emphasized Mr. Tillman's testimony that $969 million of CWIP in rate base results in a revenue requirement of $90.7 million. It argues that DTE provided no justification in its filing for this treatment. It also emphasizes Mr. Tillman's concerns that costs should be matched to the customers benefitting from the service and that including CWIP in rate base shifts risks to ratepayers traditionally assumed by

[65] See 4 Tr 677-678.
[66] See 4 Tr 678.
[67] See DTE brief, pages 29-30, DTE reply brief, pages 19-20.

the utility. Walmart cites Dr. Vilbert's testimony as an acknowledgement that including CWIP in rate base charges customers for investment that is not "used and useful."[68] Walmart also disputes Dr. Vilbert's characterization of the dispute as a "timing issue" and disputes his claim that CWIP in rate base protects customers from rate shock.[69]

In its reply brief, Walmart acknowledges that the treatment of CWIP in rate base is "a higher technical and somewhat arcane topic . . . further obscured by differences in treatment from state to state."[70] Addressing Ms. Uzenski's rebuttal testimony, Walmart notes that rate case filing requirements mandating DTE's disclosure of CWIP do not ensure that DTE will recover those amounts from customers, and provides citations to the Commission's orders in Case No. U-4771, the case in which the Commission adopted the rate case filing requirements. Walmart also discusses the Commission's order in Case No. U-5281, arguing that DTE's position in that case favored including CWIP in rate base with no AFUDC offset, which the Commission rejected, and that DTE takes the same position in this case. Walmart finds the exception for environmental pollution controls that the Commission adopted in Case No. U-5281 to be reasonable and consistent with the matching principle articulated by Mr. Tillman.[71]

This issue also arose in DTE's last rate case, Case No. U-17767. The Commission reaffirmed its use of CWIP in that case, with an AFUDC offset for non-environmental construction work in progress, noting that no party filed exceptions to the Administrative Law Judge's recommendation in that case.[72]

---

[68] See Walmart brief, page 10.
[69] See Walmart brief, pages 10-12.
[70] See Walmart reply brief, page 2.
[71] See Walmart reply brief, pages 4-6.
[72] See December 11, 2015 order, Case No. U-17767, page 36.

A review of Walmart's arguments indicates that it does not fully appreciate the significance of Ms. Uzenski's testimony. She made clear that for non-environmental CWIP the AFUDC offset protects ratepayers from any current impact on rates. Walmart does not directly address the AFUDC offset, which as Ms. Uzenski explained, eliminates any rate impact to present customers. The category of CWIP that is allowed to be included in rates for current customers is the environmental category, but as noted above, Walmart indicates that it does not object to this treatment. Although Dr. Vilbert identified what he perceives to be the benefits to including CWIP in rate base without an AFUDC offset,[73] DTE does not actually argue for a change in the Commission's current policy that only CWIP related to environmental projects can be included in rate base without an AFUDC offset, i.e. only environmental-related CWIP can be recovered from ratepayers before the plant is placed in service. Instead, in addressing Walmart's arguments, DTE cites the Commission's prior orders in Case Nos. U-4771, U-5281, and U-15244 as consistent with its own position.

For these reasons, this PFD does not find any basis to recommend to the Commission that it revise its longstanding rate case treatment of CWIP. Nonetheless, Walmart's apparent confusion on this issue is understandable. It is difficult to determine on this record what DTE has included in its CWIP balances, making it difficult to ascertain how certain expenses are being treated for ratemaking purposes. This concern is also discussed below in connection with certain rate case projections. DTE argues that it is required to include CWIP in its rate case filing, but this PFD recommends that the Commission require DTE to provide additional detail regarding its historical CWIP balances and CWIP projections. The information provided on this

[73] See 4 Tr 677-678

record states only totals and lacks meaningful information as to what projects are driving the differences in CWIP and AFUDC amounts from the historic to the projected test year.[74]

2. Production Plant (lines 1-4 of Exhibit A-9, Schedule B6)

As shown in Exhibit A-9 Schedules B6 and B6.1, DTE projects capital expenditures for non-nuclear production plant (including steam, hydraulic, and "other" production plant) totaling approximately $1.2 billion from the end of the 2014 historical test year through the projected 2016-2017 test year. Testimony in support of DTE's projection was presented primarily by Mr. Warren, with additional testimony from Mr. Stanczak and Ms. Uzenski.

Staff and the Attorney General recommend excluding contingency spending as discussed in section a below; MEC/SC/NRDC recommend that the Commission exclude projected capital expenditures associated with River Rouge Unit 3 operations as discussed in section b below; the Attorney General also recommends an adjustment to DTE's total projected routine capital expenditures as discussed in section c below; and the Attorney General and MEC/SC/NRDC recommend that the Commission deny DTE's request to include projected spending for one or more new natural-gas-fired plants as discussed in section d below.

a. *Contingency Spending*

Staff and the Attorney General both recommend excluding contingency amounts totaling $7.6 million from DTE's projected production plant capital expenditures. Staff relies on Ms. Simpson's testimony, which explained the basis for Staff's $7.6 million

[74] See, e.g., Exhibit A-9, Schedules B1 and B2 and Exhibit A-10, Schedules C1 and C11; Uzenski, 4 Tr 836-837.

adjustment to this category of expense. Staff views contingency spending as uncertain to occur, and uncertain in amount. In addition, Staff maintains that including contingency amounts in rate base may dampen incentives for cost control and will shift the risk associated with the cost projections onto ratepayers by providing for a return on and of an investment that may not be made within the test year, or ever.[75] Staff also cites the Commission's recent orders in Case Nos. U-17735 and U-17767, each concluding that including contingency amounts in projected rate base is not sound ratemaking.[76]

The Attorney General agrees with Staff that the contingency estimates should be excluded from rate base. Mr. Coppola's testimony recommended that the contingency projections be excluded from production plant as well as from capital expense projections in other expense categories discussed below.[77] The Attorney General likewise cites the recent Commission decisions cited by Staff.

DTE presented rebuttal testimony on this issue. Mr. Warren testified that "contingency" amounts are included in the initial forecast for some large projects "in case cost increases are experienced due to unforeseen circumstances."[78] He explained:

> As engineering is completed, as firm material quotes are received, and as early construction work progresses, those contingency levels are reduced as the contingency is either consumed due to emerging issues or redirected to other new work.[79]

---

[75] See 5 Tr 1557, Staff brief, pages 20-22.
[76] See November 19, 2015 order, Case No. U-17735, page 11; December 11, 2015 order, Case No. U-17767, page 19.
[77] See 6 Tr 1806-1807. The Attorney General has identified a total of $18.1 million in contingency included in DTE's capital expenses projections; each component of the Attorney General's proposed adjustment is addressed separately below in the context of the relevant expense category.
[78] See 3 Tr 156.
[79] See 3 Tr 156-157.

He testified that all budgeted funds will be invested in projects that benefit customers.[80] Mr. Colonnello also testified on the topic of contingency spending, in the context of nuclear power capital expense projections, contending that it is unreasonable to expect perfect foresight with regard to such matters, so it is necessary to maintain contingency reserves to cover these highly probably events of uncertain scope.[81] DTE cites this testimony in its briefs on this issue.[82] DTE further argues that characterizing contingency funding as speculative fails to acknowledge that contingency funds are routinely required to complete individual projects, arguing contingency funds are "part of a project's total budged cost that is expected to be incurred but which cannot be specifically identified when the project budget is first established."[83]

Staff addressed DTE's rebuttal testimony in its initial brief, arguing that any additional work the company asserts it will perform with unspent contingency allowances cannot be reviewed in this case and is thus too speculative to be considered just and reasonable.[84] Staff also emphasized that by excluding such contingent expense projections, Staff is not precluding the company from recovering actual contingency expenditures in rate base in a future case, should the money be spent. Staff's reply brief also addresses DTE's claim that it should recover a projected contingency allowance because contingency funds are a normal part of budgeting:

> In its initial brief, DTE Electric argued that Staff "neglect[ed] to acknowledge that contingency funds are routinely required to complete individual projects." (DTE Electric's Initial Brief, p 38.) However, just because contingency funds are a normal part of budgeting, that does not mean that these expenses are appropriate for recovery in rates before the

[80] See 3 Tr 157.
[81] See Colonnello, 5 Tr 1278-1279.
[82] See DTE brief, page 38; reply brief, pages 30-34.
[83] See DTE's reply brief, page 30.
[84] See Staff brief, pages 21-22.

> nature of the expenses is known. The Company's own argument underlines this point. DTE Electric states that "[a]s engineering is completed, as firm material quotes are received, and as early construction work progresses, those contingency levels are reduced as the contingency is either consumed due to emerging issues or redirected to other new work." (Id.) By definition, "emerging issues" and "other new work" are unknown expenses.
>
> The Company should not earn depreciation and return on undefined speculative spending needs; dollars that may even remain unspent. As Staff argued in the Company's last rate case, the uncertainty about these projected expenditures inhibits Staff's ability to ensure that the Company's costs are just and reasonable.[85]

In its reply brief, DTE argues that Staff "appears to misperceive the contingency portion of a project as extra funding." It argues:

> Instead, contingency is part of a project's total budgeted cost that is expected to be incurred, but which cannot be specifically identified when the project budget is first established. Staff's proposal would be counterproductive because contingency costs are real project costs. Reducing project funding by excluding contingency would not reduce project costs; instead it would require reducing the project scope (to the reduced funding level) or cutting other projects (to fund the whole cost of the project).[86]

Recognizing Staff's argument that that reasonable and prudent costs can be included in rate base in future cases, DTE then asserts: "Thus, only a narrow question remains—essentially how much proof does DTE Electric need to recover its costs now instead of later."[87]

This PFD concludes that Staff and the Attorney General have correctly analyzed the appropriate ratemaking treatment for contingency spending. The Commission has made clear that projected contingency capital expenditures are not appropriate for inclusion in the projected rate base used for setting rates:

---

[85] See Staff reply brief, page 7.
[86] See DTE reply brief page 30.
[87] DTE reply brief, pages 30-31.

> The Commission agrees with the ALJ, the intervenors, and the Staff that the $4.1 million in air quality related contingency costs should be excluded, because, while contingency planning is an acceptable budgetary strategy, it is not appropriate for ratemaking. See, the November 19, 2015 order in Case No. U-17735. As the Staff correctly notes, contingency budgeting is speculative, and shifts all of the risk associated with that item onto ratepayers, allowing for a return of and on an investment that may never be made.[88]

DTE has provided no basis to reconsider the Commission's recent determinations on this issue in Case Nos. U-17735 and U-17767. Indeed, DTE does not address the Commission's prior decisions on this issue. DTE's claim that projected contingency amounts are "real costs" is not credible and is contradicted by the testimony of its own witnesses that if the money is not spent on a particular project, it will be spend on something else. As Staff argues, should actual capital costs be higher than projected, as long as they are reasonable and prudent expenditures, DTE will be able to include those expenditures in its rate base in future years and future rate cases.

b*. River Rouge Units 2 and 3*

Following its February 2016 filing in this case, DTE decided to shut down River Rouge Unit 2 after an extended outage. DTE did not amend its filing to expressly address the shutdown, and did not even amend Mr. Warren's testimony and exhibits discussing DTE's plans for the unit.[89] As discussed below, in its briefs in this case DTE acknowledged the need to exclude from its rate request in this case the O&M costs

[88] See December 11, 2015 order, Case No. U-17767, page 19.

[89] See, e.g., Warren, 3 Tr 132 ("The nine tier 2 coal units (St Clair 1-4, 6&7, River Rouge 2&3 and Trenton Channel 9) are receiving 15% of the total investments which is directed towards their routine capitalized maintenance while 17% is being directed total towards their non-routine environmental requirements. It should be noted that maintenance must still be performed on the tier 2 plants to ensure that they operate safety and with reasonable reliability during their sunset years."); Tr 146 ("During the projected test year running from August 1, 2016 and ending July 31, 2017, the Company will execute nine periodic maintenance outages on Belle River Unit 2, Greenwood, St Clair Units 3, 4 and 7, River Rouge Unit 2, Trenton Channel Unit 9 and Monroe Units 2 and 4. As in the historic period, short duration unit tune-up outages will also be completed on the St Clair, Belle River, River Rouge, Trenton Channel and Monroe Units to optimize continuing performance.")

projected for River Rouge Unit 2. But instead of providing affirmative testimony revising its cost projections, DTE relies on a discovery response provided to MEC/SC/NRDC, which they introduced as Exhibit MEC-33, as the basis for its revised capital expense projections.[90] As this discovery response to MEC/SC/NRDC indicated, DTE plans to "redirect" projected capital expenditures for River Rouge Unit 2 to other capital projections.

Mr. Sansoucy provided the only narrative testimony explaining the events leading to the shutdown of River Rouge Unit 2. Mr. Sansoucy cited testimony by DTE witness Michael Banks in DTE's 2015 PSCR reconciliation case indicating that River Rouge Unit 2 had been on forced outage since July of 2015 due to a likely crack in its turbine rotor, and that DTE had informed MISO that the unit will be retired on June 30, 2016, as shown in Exhibit MEC-28.[91] He recommended that the Commission exclude projected capital costs for River Rouge Unit 3 until DTE establishes that it will be cost-effective to continue to operate this unit given the shut-down of River Rouge Unit 2.

Mr. Sansoucy explained that DTE conducted a cost-benefit analysis prior to making the determination to retire River Rouge Unit 2 and concluded that the "Net Present Value Revenue Requirement" (NPVRR) of repairing Unit 2 would be greater than retiring it.[92] He explained his concern that DTE had not also analyzed the economics of continuing to operate River Rouge Unit 3:

> Because DTE's own 2015 Net Present Value analyses of River Rouge – if updated with current information – would very likely show that early retirement of Unit 3 is more economic than continued operation of that unit by itself, I recommend that the Commission deny projected test year common plant expenditures not related to retiring the plant; or at a

[90] See Warren, 3 Tr 155.
[91] See 5 Tr 1661.
[92] See 5 Tr 1661-1662.

> minimum put DTE on notice that the Commission will likely deny approval of capital or major maintenance expenditures not related to retiring Unit 3 as soon as possible.[93]

He cited a discovery response indicating that DTE had analyzed the economics of operating both units in July and August of 2015, prior to the Unit 2 failure. He also cited a discovery response from DTE indicating that DTE had not evaluated the economics of continuing to operate River Rouge Unit 3 given the retirement of Unit 2, presented in his Exhibit MEC-31.

Mr. Sansoucy explained three reasons for his opinion that such an analysis would show the economics of continuing to operate Unit 3 are not favorable, including common plant costs that can no longer be shared with Unit 2, market capacity prices 18% below those used in DTE's pre-failure analysis of the economics of operating both units, and forecast market energy prices 9-12% below those used in that prior analysis.[94] He provided additional information regarding the assumptions DTE used in its analysis of the economics of operating River Rouge Unit 2 in his Exhibit MEC-32 and MEC-33.

Mr. Sansoucy testified that by no longer sharing common costs with Unit 2, Unit 3 would need to absorb approximately $4-8 million additional annual O&M costs and an additional $1.5 million common annual capital costs.[95] He also presented charts showing the difference in capacity and energy prices used in DTE's pre-failure analyses and the prices used in its recent analysis of the economics of continuing to operate Unit 2.[96] He referenced Mr. Warren's discovery response indicating that no capital projects

[93] 5 Tr 1648-1649.
[94] See 5 Tr 1662-1663.
[95] See 5 Tr 1665.
[96] See 5 Tr 1665-1666.

are planned for Unit 3 that are expected to cost over $1 million and indicating total projected capital maintenance costs of $1.6 million in 2016 and 1.1 million for the first seven months of 2017.[97] He recommended that the Commission deny the inclusion in rate base of any and all common plant capital or major maintenance expenditures on the plant that are not directly related to an expeditious retirement of the whole plant: "DTE has not shown that continuing to spend ratepayer money on Unit 3 is an economic course of action, and there is substantial evidence that indicates it is not an economic course of action."[98]

In rebuttal, Mr. Warren testified regarding DTE's planned capital expenditures:

> While no project individually reached the $1 million threshold in 2016 or 2017 for the River Rouge Power Plant, there are capital expenditures that are required at River Rouge associated with the continued operation of the plant. These expenditures are mainly related to routine replacements of pumps, motors, valves, and control system components. These replacements are required for safety, environmental compliance and other routine maintenance activities and do not represent new significant capital investments as stated by Witness Sansoucy. These routine component replacements are capitalized and not expensed in line with established accounting policy.[99]

DTE cites Mr. Warren's rebuttal testimony in its brief, explaining that DTE does not propose to spend more than $1 million on any single maintenance project for Rouge River Unit 3, although it plans to spend more than $1 million total in both 2016 and 2017. In its reply brief, DTE further argues that it is speculative to conclude that continued operation of River Rouge Unit 3 is uneconomical for customers. DTE also

[97] See 5 Tr 1667.
[98] See 5 Tr 1667.
[99] See 3 Tr 155-156.

argues that MISO approval is required to shut down the unit, and contends there is considerable uncertainty regarding the availability and cost of future capacity.[100]

In their briefs, MEC/SC/NRDC argue that the Commission should exclude projected capital expenses for River Rouge Unit 3 of $1.7 million in 2016 and $1.1 million for the first seven months of 2017, as shown in Exhibit MEC-33, and apprise DTE that all capital and major maintenance expenses not related to retiring the plant will be disallowed.[101] They argue that DTE did not dispute Mr. Sansoucy's testimony regarding the expected result of an economic analysis of continuing to operate Unit 3 given that common plant costs previously shared between the units will now be borne by Unit 3 alone, and capacity and energy price forecasts are now below the level used in DTE's last economic analysis. MEC/SC/NRDC also cite DTE's revised O&M cost projections for Unit 3, shown in Exhibit MEC-33, arguing that DTE has assigned significantly more than half the total O&M cost previously associated with operating both units.[102] MEC/SC/NRDC argue that DTE has the duty to present evidence in support of its requested rate increase and has the burden to establish by a preponderance of the evidence that its projected costs and rates are just and reasonable, and that DTE has not met these requirements.[103]

This PFD finds that DTE has not performed an analysis of the continued economics of operating River Rouge Unit 3 in light of the shutdown of River Rouge Unit 2. Without such an analysis, the reasonableness and prudence of DTE's projected capital expenditures cannot be evaluated. While DTE is correct that MISO approval is

[100] See 3 Tr 155-156; also see DTE brief, pages 37-38, DTE reply brief, pages 28-30.
[101] See MEC/SC/NRDC brief, pages 3-11.
[102] See MEC/SC/NRDC brief, page 7.
[103] See MEC/SC/NRDC brief, page 9.

required before the unit can be shut down, a reasonable analysis is the clear predicate to a determination whether that MISO approval should be sought. Clearly, DTE has the tools to perform such an analysis as shown by the several NPVRR analyses it has performed at other key decision points. On this basis, this PFD finds that it is not appropriate for ratepayers to fund capital expenditures for River Rouge Unit 3 in advance of DTE incurring such costs. Instead, DTE should be prepared to support the reasonableness and prudence of any capital expenditures on this plant that it seeks to include in rate base in its next rate case. While the amount of the projected expenditures are relatively small, the principle that DTE bears the burden to establish the reasonableness and prudence of projected capital expenditures, as well as the certainty of the expenditures, is an important principle. Here, DTE did not even bother to amend its case to address this significant change and certainly did not meet its burden of persuading the Commission that the projected expenses are appropriate for inclusion in rate base. In addition to excluding projected capital costs for River Rouge Unit 3 from rate base in this case, this PFD recommends that the Commission admonish DTE that its testimony and exhibits are expected to be accurate when introduced into evidence and it cannot rely on other parties to fill in gaps or correct its errors.

c*. Routine Capital Expenditures*

The Attorney General recommends excluding a total of $12.1 million associated with "routine" capital expenditures to maintain the generating units. Mr. Coppola testified that DTE is projecting an increase of $192.5 million in routine capital expenditures, which he characterized as a significant increase from recent years. He presented 2013 through 2015 expenditures in his Exhibit AG-18, showing an average expenditure of $180.4 million. He also testified that DTE's projections for the first seven months of 2017, if extrapolated to a full year, would only be $181.2 million. Focusing on the 44 projects projected to cost over $1 million, Mr. Coppola testified that the average cost of these projects is greater than in prior years and he characterized the estimates as "ball-park" estimates not "specifically determined and reliable." On this basis, he recommended that the routine maintenance capital expenses projected for 2016 be reduced from $192.5 million to the most-recent three-year average spending level of $180.4 million, a reduction of $12.1 million.[104]

In rebuttal, Mr. Warren testified that DTE's routine maintenance expenses vary from year to year, and for 2016 DTE's projected expenses include a major periodic outage for the Monroe plant in both 2015 and 2016, with a cost estimate for the 2015 outage for Unit 3 of $50.2 million and a cost estimate for the 2016 outage for Unit 4 of $71.7 million. He testified that this difference alone exceeds the average $12.1 million difference Mr. Coppola observed between 2016 projected expenditures and the 2013 through 2015 expense levels.[105] DTE relies on Mr. Warren's testimony in its brief and reply brief on this issue.[106]

The Attorney General argued in his brief that the Commission should make this adjustment, but the Attorney General does not acknowledge Mr. Warren's rebuttal testimony or address the impact of the 2016 Monroe Unit 4 planned outage.[107] Because the Attorney General does not dispute Mr. Warren's testimony regarding the

[104] See 6 Tr 1812-1814.
[105] See 3 Tr 157-158.
[106] See DTE brief, pages 38-39.
[107] See Attorney General brief, see pages 38-39.

projected expense for Monroe Unit 4, this PFD recommends that the Commission reject the Attorney General's proposed adjustment in this category. In making this recommendation, this PFD notes that contingency amounts have already been excluded from the company's projections, as discussed above, as well as River Rouge Unit 3 projected capital expenditures, and further, Mr. Warren's testimony providing expenditures for routine maintenance linked to planned outages are reviewed by the company's Fossil Generation Capital Governance Board (CGB).[108] This PFD finds that DTE has established that it has reliable plans for routine maintenance of its generating units, and with the exception of the River Rouge adjustments recommended above, its non-contingency projected expenditures are reasonable and prudent maintenance activities.

d*. New Build*

The Attorney General and MEC/SC/NRDC recommend excluding proposed spending related to DTE's potential construction of one or more new natural gas plants. Mr. Warren testified regarding DTE's plans as follows:

> Starting in 2020, Fossil Generation is tentatively forecasting the retirements of multiple coal fired facilities and the addition of new combined cycle and simple cycle gas turbine units. No formal approvals have been obtained for these additional unit retirements, nor for procuring/building additional new generation units; therefore, specific details on these options is not available at this time. [109]

Mr. Warren's testimony in support of DTE's request to include proposed capital expenditures of $13.2 million in rate base was limited to this statement and the following

[108] See 3 Tr 104-16, DTE brief, page 36 at n 43 ("The Company's capital expenditure approval process is a rigorous capital spending and approval process that is designed to identify the optimal allocation of capital resources to meet safety and environmental regulations, while maintaining overall Fossil Generation reliability performance and reducing costs.")
[109] See 3 Tr 96.

comments on two lines of his Schedule B6.1. Regarding line 3 of Schedule B6.1, page 1, he testified:

> Line 3 Non-Routine Steam Power includes capital expenditures such as site closure and required equipment modifications related to retired power generation assets, engineering associated with planned build of new gas fuel generation assets and other land improvement projects such as expansion of the Greenwood Energy Center cooling water system.[110]

Regarding line 5 of Schedule B6.1, page 2, he testified:

> Line 5 New Build is a $13.2 million project covering early stages of engineering technology selection, permitting, and site evaluations for potential future construction of new natural gas fueled generating units.[111]

Mr. Stanczak also testified: "As supported by Company Witness Mr. Warren, DTE Electric is tentatively forecasting the retirements of multiple coal fired power plants and the addition of new combined cycle and simple cycle gas turbine facilities starting in 2020."[112]

Mr. Coppola explained his recommendation that the Commission exclude these projected expenditures from rate base:

> In response to various discovery request from the AG, Staff and other parties to the case, the company has divulged that it is still in the study phase of potential construction of new generation plants and could not provide any details as to timing of construction, location, size of facilities, estimate cost or economics of the projects being considered. In other words, the Company has no basis to justify the expenditures being incurred and whether or not they will lead to the construction or acquisition of productive assets. Without more certainty that the effort will lead to plant additions that are used and useful, the Company's proposal fails the basic test of inclusion of the proposed expenditures in rate base for recovery of depreciation and a return on the rate base additions.[113]

---

[110] See 3 Tr 109.
[111] See 3 Tr 113.
[112] See 4 Tr 1096.
[113] See 6 Tr 1814.

Mr. Jester also presented testimony on this issue, recommending that the Commission defer a determination of both “return of” and “return on” the natural gas plant development costs to the CON case or other regulatory filing that DTE plans to make in support of the project. First, he testified that the CON process is a specific proceeding available by statute to address recovery of these costs, and second, he testified:

> [I]n combination with the Fermi 3 request, DTE is asking the Commission to approve rate base treatment of capital expenditures on two types [of] generating assets that represent alternative long-term generation resource plans that are inconsistent with each other. DTE’s long-term plan included Fermi 3 and no combined cycle gas units, until Fermi 3 was taken out and combined cycle gas units were added. Mr. Paul’s testimony from the PSCR plan case quoted above indicates that the Fermi 3 and combined cycle gas are alternatives to each other. Exhibit MEC-11 states at page 9 that “If natural gas prices and/or costs of CO2 abatement rise, the economics of a nuclear investment could become favorable when compared to NGCC for baseload generation.” DTE customers should not be placed in the position of paying both the costs of and a return on expenditures for planning and permitting mutually inconsistent generation facilities, without any specific limit on the amount of the expenditures or the time frame in which expenditures can continue to be made before the merits of the projects are determined through the statutory process created for that purpose.[114]

Although Staff has not addressed this issue in its briefs, Ms. Simpson testified that Staff supported including the proposed new build expenditures. She presented a discovery response from the company as part of her Exhibit S-13 that indicates that DTE at least planned at the time of its response to treat these expenditures as Construction Work in Progress (CWIP): “All of the costs above are or will be recorded in FERC Uniform System of Accounts Construction Work-in-Progress (107).” Consistent with that discovery response, Mr. Krause testified as follows:

Q. Does Staff agree with the accounting treatment for new gas build?

[114] See 5 Tr 1640.

> A. The new build is recorded in Construction Work in Progress (CWIP) with an appropriate amount of Allowance for Funds Used During Construction (AFUDC) offset. Staff agrees that this treatment is appropriate.[115]

Notwithstanding Staff's understanding that these projected expenditures were treated as Construction Work in Progress with an AFUDC offset, DTE objected to the Attorney General's and MEC/SC/NRDC's recommendations, arguing that it *should* recover the cost of these projected expenditures in current rates. In his rebuttal testimony, Mr. Warren responded that Mr. Jester's recommendation to defer recovery of these projected expenses should be given no weight.[116] He asserted that Mr. Jester did not understand that the purpose of the new build expenditures is to determine details such as the location of a new plant and to support a complex Certificate of Necessity application meeting the requirements outlined in the Commission's December 23, 2008 order in Case No. U-15896.[117] Mr. Warren also testified:

> [A]n investment to prepare for the extensive requirements laid out by the MPSC in its CON process in both timely and required. Additionally, with expectations that a new combined cycle gas turbine generating plant will have an investment cost approaching $1 billion it is prudent that a 1% early investment is required to answer the myriad of topics required by the CON process and to help the Company evaluate the best investment decisions on behalf of our customers."[118]

In its briefs, DTE relies on Mr. Warren's rebuttal testimony.[119] In its reply brief, DTE further responds that MEC/SC/NRDC's arguments would require it to have the results of the study before it has conducted the study. Neither Mr. Warren in his testimony nor DTE in its briefs addressed Mr. Jester's concern that the proposed natural

---

[115] See 5 Tr 1489.
[116] See 3 Tr 154.
[117] See 3 Tr 152-154.
[118] See 3 Tr 159.
[119] See DTE brief, page 37.

gas plant(s) are inconsistent with the pending Fermi 3 license. Neither Mr. Warren nor DTE refuted Mr. Coppola's or Mr. Jester's claim that DTE was proposing to collect a return on and a return of these projected expenditures from current customers, which would be incorrect if DTE were treating these projected expenditures as CWIP with an AFUDC offset. As discussed above, Ms. Uzenski explained clearly that CWIP with an AFUDC offset does not impact current ratepayers.

Arguing that the authority granted in 2008 PA 286 does not diminish the Commission's ratemaking authority in this case, DTE acknowledges it is asking the Commission to ignore the "used and useful" test, citing several cases predating 2008 PA 286 to show that the Commission is not bound to apply any particular formula or using any particular method in settings rates.[120] DTE argues: "The relatively small costs to get answers to numerous initial issues, and to help the company evaluate the best investment decisions on behalf of its customers, are reasonable and prudent" as discussed in Mr. Warren's testimony.[121]

In their brief, MEC/SC/NRDC cite Mr. Jester's and Mr. Coppola's testimony, and present several reasons why the Commission should not provide rate base treatment for these preliminary expenditures.[122] First, they argue that DTE has not established that the proposed expenditures will be reasonable and prudent, also citing discovery responses in Exhibits MEC-13 and MEC-14. Second, they argue that DTE's proposed rate base treatment is an end-run around the Certificate of Necessity process provided in 2008 PA 286, MCL 460.6s, and may exceed the Commission's authority in light of

---

[120] See DTE reply brief, page 28, and n24, citing *ABATE v Public Service Comm*, 208 Mich App 248, 258-59 (1994); *Detroit Edison Co v Public Service Comm*, 127 Mich App 499, 524 (1983), and *Residential Ratepayer Consortium v Public Service Comm*, 239 Mich App 1, 6 (1999).
[121] See DTE reply brief, page 27.
[122] See MEC/NRDC/SC brief, pages 21-28.

that statute. They note that MCL 460.6s expressly provides for the recovery of siting and licensing costs, and that DTE has indicated that it plans to seek a Certificate of Necessity for the plant as early as early as 2017. Third, MEC/SC/NRDC reference DTE's requested cost recovery for Fermi 3 licensing expenses, arguing that DTE has indicated that a new gas plant would be an alternative to building the Fermi 3 nuclear plant, thus making the company's requested cost recovery for both projects inconsistent. MEC/SC/NRDC take issue with Mr. Warren's testimony that it is reasonable for ratepayers to pay 1% of the projected cost of a new plant before its location, size, and other basic information have been presented. In addition, MEC/SC/NRDC argue that confusion arose over DTE's requests to recover the Fermi 3 licensing expenses and that it would be best for the Commission for prudential reasons to await the company's filing of a Certificate of Necessity application and the creation of an evidentiary record in that case:

> Fermi 3 provides a cautionary tale. DTE filed its first request to recover initial planning costs for the Fermi 3 facility in 2007. The Commission has now issued five orders related to Fermi 3 costs AS discussed above, DTE has spent over $100 million to date on that project (and growing), and there is still no timeline to make a build decision. Rather than following the Fermi 3 model for cost recovery by piecemeal consideration in rate cases, the Commission should instruct the company to follow the alternative process specifically created by the Legislature to address new generation construction project costs.

First, this PFD agrees with MEC/SC/NRDC and the Attorney General that DTE has not supported the reasonableness and prudence of its proposed expenditures. The discovery responses to interrogatories seeking detailed information regarding the proposed expenditures were not adequate to permit proper evaluation by the parties, as

Mr. Coppola and Mr. Jester testified. In Exhibit MEC-13, asked to provide the "stage or status of planning", DTE responded:

> DTE Electric is in the study phase of a project to build a new facility(ies) to support future generation needs of our customers. Current efforts include alternative technology studies, technical specification development, request for proposal development, siting studies and environmental studies.[123]

Asked to "describe in detail the expenditures projected for the test year," DTE responded:

> The projected expenditures consist of incremental costs associated with the study phase of project to build a new facility(s) including, but not necessarily limited to, alternative technology studies, technical specification development, request for proposal development, siting studies, environmental studies, increment project management, owner's engineer, and corporate overheads.[124]

DTE's response to Staff's request for information, contained in Exhibit S-13, Schedule S-13.4, was not significantly more expansive; it breaks down the projected costs into the categories supplied by Staff, but does not explain what is included in any cost category or how the identified cost was determined. The cost categories included: reporting costs for benchmarking, community outreach, EPRI studies, IRP and contracting support, owners engineer, RFP and contracting support, siting study, technical specification and development, consulting and contracted services, project management, corporate overhead and AFUDC, and contingency. Of the total of $12.5 million in non-contingency amounts shown on the exhibit, $1.9 million is identified as "Corporate Overhead and AFUDC." DTE's response also indicated as follows:

> The following services have been contracted including: benchmarking, EPRI studies (EPRI contracted), IRP and contracting support, siting study, technical specification development. Contracted Services shown in

[123] See Exhibit MEC-13, page 5.
[124] See Exhibit MEC-13, page 6 (emphasis added).

> STDE1.3 is a summary of all the above line items, except Project Management, Corporate Overheads and AFUDC.
>
> All of the costs above are or will be recorded in FERC Uniform System of Accounts Construction Work-in-Progress (107).

DTE did not provide any specific contract amounts, did not provide a contract for review, and did identify the first steps it would take if provided with ratepayer funding. DTE has not explained why it believes that it will progress to siting and community relations issues, for example, regarding a proposal that it has no understanding yet whether it will be economically feasible, and whether it will build one or multiple plants, among other unanswered questions. Under cross-examination from the Attorney General, Mr. Warren appeared to agree that he did not provide support for the $13.2 million expenditure in his direct testimony, pointing instead to his rebuttal testimony.[125] Additionally, consistent with the discussion in section 1 above, DTE's filing does not contain sufficient information do determine whether the projected expenditures for this category are treated as CWIP with an AFUDC offset, as DTE told Staff it would account for the transaction, or included in rate base without an AFUDC offset, consistent with DTE's claim that it should be able to recover its projected capital engineering and planning costs from current customers.

This PFD also finds no reason to overturn or revise the usual ratemaking presumption that capital costs are included in rate base when they reflect investments that are used and useful in providing service to customers. If DTE simply follows the CWIP accounting outlined in its discovery response to Staff, it can seek recovery through a Certificate of Necessity under MCL 460.6s, or when it puts a new plant or plants in service. Note, too, that the Commission has provided for recovery of

[125] See 3 Tr 171.

engineering expenses when a utility has decided to cancel construction of a plant.[126] Although DTE correctly cites a line of cases indicating that the Commission has broad authority to provide for the recovery of investments that are not used and useful, the courts have not addressed MEC/SC/NRDC's claim that MCL 460.6s limits the Commission's authority to provide for the advance recovery of construction costs that are eligible for a Certificate of Necessity, when no Certificate has been granted. Without resolving this legal question, for the reasons stated above, this PFD recommends that the Commission exclude the additional $13 million in projected expenditures for the new build evaluation.

3. MERC/Fuel Supply (line 5 of Exhibit A-9, Schedule B6)

Mr. Milo presented testimony supporting DTE's projected capital spending for DTE's Fuel Supply operations and for the Midwest Energy Resources Company (MERC), as shown in line 5 of Schedule B6 of Exhibit A-9 and in Schedule B6.8 of Exhibit A-9. The Attorney General's recommended contingency adjustment excluded $.333 million in contingency spending DTE projected for this category, as shown in Exhibit AG-15. Mr. Milo did not provide testimony explicitly addressing this contingency amount, and DTE does not address it outside the context of its general arguments regarding contingency spending discussed in section 2 above.[127] In its reply brief, DTE indicates that it does not believe there are any issues related to this expense category.[128] For the reasons discussed above, this PFD concludes that the Attorney General's recommendation is reasonable and consistent with the Commission's decisions in Case Nos. U-17767 and U-17735 and should be adopted. DTE's

[126] See June 7, 2012 order, Case No. U-16794, pages 36-37.
[127] See DTE brief, pages 68-69.
[128] See DTE reply brief, page 53.

arguments generally supporting the recovery of contingency projections are not persuasive.

4. <u>Nuclear Plant Capital Expenditures (line 6 of Exhibit A-9, Schedule B6)</u>

Mr. Colonnello presented DTE's testimony in support of its capital expense projections for Fermi 2, reflected in line 6 of Schedule B6 of Exhibit A-9, with additional detail presented in Schedule B6.2 of that exhibit. The Attorney General proposed two reductions to the capital expense projections, as discussed in sections a and b below.

a. *Contingency*

The Attorney General identified $4.480 million in "contingency" spending in DTE's capital expense budget projections for Fermi 2, as shown in Exhibit AG-15, and recommended that these amounts be excluded. Mr. Coppola's testimony on this topic was discussed in section 2 above. Mr. Colonnello also provided rebuttal on this issue, providing his opinion that the likelihood DTE will use the projected contingency expenditures is not low, and he believes there is "a high likelihood for unforeseen project risks."[129] Mr. Colonnello identified the types of "emergent conditions" that can arise during a year, due to inspections or new regulations, and testified: "Since it is unreasonable to expect perfect foresight of the exact outcome of such inspections or emerging regulations, it is necessary to maintain contingency reserves to cover a highly probably event with an uncertain scope."[130] DTE reiterates this in its brief.[131] This PFD finds that the Attorney General's recommendation is consistent with the Commission's prior orders in Case Nos. U-17767 and U-17735, and should be adopted. Mr. Colonnello's rebuttal testimony on this point does not establish that the contingency

[129] See 5 Tr 1278.
[130] See 5 Tr 1279.
[131] See DTE brief, pages 43-44.

amount will be spent on the specific projects identified, and does not establish when it will be spent.

b. *Refueling Outage Maintenance*

The Attorney General also recommends another adjustment to projected capital spending for Fermi 2 maintenance. Reviewing the capital expenditures in this category, as shown in Mr. Colonnello's Schedule B6.2 of Exhibit A-9, Mr. Coppola testified that the projected routine maintenance expenses for 2017 seem out of line with historical expenditures. He testified that DTE's response to discovery seeking an explanation of projected expenditures for "Main Turbine Refurbishment" (lines 16 and 10 of Schedule B6.2) and "Undervessel Replacement" (line 12 of Schedule B6.2) stated that the expenditures were designed for the 2018 refueling outage. He presented the response as Exhibit AG-24. Testifying that the company did not provide an explanation why it included the expenses in rates so far in advance of the refueling outage, he recommended that the Commission limit the 2017 expenditures included in test year rates to the projected expenditures for 2016. The resulting adjustment reduces forecast nuclear operations capital expenditures by $24.7 million.[132]

In his rebuttal testimony, Mr. Colonnello took issue with Mr. Coppola's method of annualizing DTE's projected expenditures for the first seven months of 2017 to derive a projected expenditure for the entirety of 2017.[133] He testified that the timing of the capital expenditures is more predominant in the first half of the year because the refueling outage is scheduled for the spring of 2017. Mr. Colonnello then testified that

[132] See 6 Tr 1826-1828.
[133] See 5 Tr 1273-1274.

Mr. Coppola had misread a portion of his discovery response regarding the turbine refurbishment projects:

> As stated on lines 10-12 on page 59 of Witness Coppola's testimony, Witness Coppola misinterpreted the response provided by the Company to AGDE-2.74a by concluding that all of the expenditures for the Main Turbine Refurbishment projects align only with the fall 2018 refueling outage and makes no mention of the spring 2017 refueling outage during which the work also occurs. Based on his misinterpretation, Witness Coppola appears to mistakenly believe that all of the expenditures are outside of the test year.
>
> * * *
>
> The response clearly states that two of the three low pressure turbines are timed for the spring 2017 refueling outage. I have included the Company's response to AGDE-2.74a as Exhibit A-27, Schedule Q2 to this rebuttal testimony.[134]

Regarding the undervessel replacement, however, Mr. Colonnello acknowledged that his initial discovery response was incorrect:

> Q. With regard to the Undervessel Replacement, upon what basis has Witness Coppola concluded that these expenditures will not likely occur until after the projected test year period in this case?
>
> A. Witness Coppola, apparently, reviewed the response provided by the Company to AGDE-2.74b and concluded the expenditures for Undervessel Replacements are outside of the test year.
>
> Q. To be clear, when are the Undervessel Replacement expenditures as noted by Witness Coppola going to occur?
>
> A. The work is going to occur in the spring of 2017 during refueling outage 18. The initial response to AGDE-2.74b was prepared by me *and I mistakenly noted the timing of these expenditures for 2018 instead of refueling outage 18 which will take place in spring 2017*. I have included the Company's revised response to AGDE-2.74b as Exhibit A-27, Schedule Q3 to this rebuttal testimony.[135]

Although the Attorney General quotes Mr. Coppola's testimony in his brief, neither in his brief nor in his reply brief does he discuss Mr. Colonnello's rebuttal

[134] See 5 Tr 1275.
[135] See 5 Tr 1276 (emphasis added).

testimony or address his rebuttal exhibit.[136] On this basis, recognizing that Mr. Colonnello provided a corrected discovery response as shown in Exhibit A-27 regarding the undervessel replacement expenses, although he had initially provided incorrect information to the Attorney General regarding the timing of the expenses, this PFD finds that Mr. Colonnello satisfactorily addressed Mr. Coppola's concern regarding the timing of the routine maintenance expenses associated with the refueling outage planned for the spring of 2017, and recommends that the Commission reject the Attorney General's $24.7 million reduction in capital spending for the two turbine refurbishments and the undervessel replacement.

5. Distribution System (line 7 of Exhibit A-9, schedule B6)

This section addresses DTE's projected capital expenditures for distribution operations without consideration of tree trimming expenses, which are discussed separately below. Mr. Whitman presented testimony in support of DTE's projected $1.3 billion in capital expenditures for 2015 through the end of the projected test year. Mr. Whitman described the Distributions Operations organization at DTE, and testified to DTE's commitment to providing safe, reliable and affordable power. Regarding its capital expense projections, he testified:

> In addition to inflationary pressures, failures associated with DTEE's aging infrastructure, growth in customer connections and the increased need for distribution asset relocations are all requiring capital funds. If capital funding remains stagnant with the increased demands on capital associated with aging infrastructure, connecting customers and relocations, reliability will continue to degrade from already unacceptable levels.[137]

[136] See, e.g. Attorney General's brief, pages 45-46.
[137] See 3 Tr 283.

He provided the following context to his testimony:

> DTEE is at a crossroads. DTEE's reliability is degrading and consistently ranks in the fourth quartile among peer utilities with respect to standard measures of reliability. Reactive work in response to tree related outages and the Company's aging electric system coupled with increasing demand for customer connections and relocation activities is placing unprecedented demand on resources.[138]

Mr. Whitman's Schedule B6.3 presents DTE's capital projections through the 2016-2017 test year, and he provided an overview of these expenditures in "Part VII" of his testimony.[139]

Staff and the Attorney General recommended adjustments to these expense projections that are difficult to compare since these parties take different approaches to formulating their recommendations for this category of expense. MEC/SC/NRDC also made a recommendation relating to this capital expense category. In the discussion that follows, Staff's recommendation is discussed in section a, the Attorney General's recommendations are discussed in section b, and MEC/SC/NRDC's recommendation is discussed in section c. Although this PFD makes findings in each section, concluding recommendations for the Commission are presented in section d.

a. *Staff's Recommendation*

Staff recommends an adjustment to DTE's total projected spending in this category that would provide for a 10% annual increase in the level of capital spending for 2016 and 2017. Mr. Mazuchowski reviewed DTE's total distribution system capital expenditures from 2012 through 2015 and its projections for 2016 and 2017 presenting a comparison in Exhibit S-9, Schedule 9.3. He also presented DTE's capital expense projections from Case No. U-17767, and testified that DTE did not spend as much in

[138] See 3 Tr 284.
[139] See 3 Tr 338-344.

2015 or 2016 as it projected in that case. In Mr. Mazuchowski's opinion, DTE's projected increases of 18% for calendar year 2016 and 8% for 2017 are unreasonably high. He testified that although DTE has significantly increased its capital spending for several years, reliability should have improved but has not.[140] He testified that DTE's proposed capital spending also does not show any corresponding O&M savings that one would expect to occur from the increase in capital spending.[141] Mr. Mazuchowski compared DTE's spending levels, capital and O&M, to the per-customer spending levels of other utilities, and he compared DTE's performance statistics, as shown in Exhibit S-9, Schedule 9.4. He testified that DTE's proposed capital spending is approximately 5% lower than the average of seven utilities with over 1 million customers each.[142] Mr. Mazuchowski recommended that the Commission allow for an increase of 10% over 2015 levels for 2016 and an additional increase of 10% for 2017 capital spending. Mr. Gerken testified that Staff's adjustment results in a $39.2 million reduction to DTE's proposed rate base plant in service.[143]

In rebuttal, Mr. Whitman testified that DTE has spent more than it forecast and more than the Commission approved in each of the last four years, presenting Exhibit A-28, Schedule R3 to support his testimony.[144] He testified that not enough time has elapsed to determine if positive reliability improvements are occurring.[145] Correcting a figure in an earlier version of Staff's Exhibit S-9, Schedule 9.3, Mr. Whitman disagreed with Staff's recommended capital expense amounts, arguing that the fact that DTE has

[140] See 5 Tr 1513-1514.
[141] See 5 Tr 1514-1515.
[142] See 5 Tr 1515-1516.
[143] See 5 Tr 1476.
[144] See 3 Tr 366-367.
[145] See 3 Tr 366.

been spending 5% less in capital than its peers supports increasing the company's capital expenditures. He labeled Staff's 10% annual increase "arbitrary".[146] Mr. Whitman further testified that DTE listed specific projects "to improve reliability and address customer requests" in one of its workpapers that included engineering estimates and contended that the $34.1 million difference in projected expenses for 2017 would lead to reduced reliability work and have a negative impact on customers.[147]

In its briefs, DTE relies on Mr. Whitman's rebuttal testimony. DTE disputes that it spent less than its rate case projections in Case No. U-17767 once tree trimming capital expense projections are excluded consistent with the Commission's decision in that case. The main thrust of DTE's argument is that the very poor performance it has shown clearly justifies additional capital spending. The introduction to DTE's brief on this expense category argues:

> DTE Electric's key responsibility is to provide safe, reliable and affordable power to the residents and businesses in the Company's service territory. Customers need reliable service, yet the Company's system reliability is degrading and consistently ranks in the fourth quartile among peer utilities. There is unprecedented demand on Company resources to address reactive work in response to tree related outages, as well as increasing demand for customer connections and relocation activities. Aging infrastructure throughout the Company's service territory also requires reconfiguration and replacement. Therefore, DTE Electric requires $568 million in capital and $308 million in O&M for the projected test period, as further outlined below. Without this necessary funding, there would be unacceptable risks impacting customer reliability and electric system integrity.[148]

[146] See 3 Tr 369-370.
[147] See 3 Tr 370.
[148] See DTE brief, pages 45-46.

DTE argues that Staff's 10% annual increase in capital expenditures is unreasonably low, and is contrary to Staff's recognition that DTE is spending less than its peers.[149] DTE further argues that its capital request is supported by detailed analysis and engineering estimates for specific projects to address customer requests and improve reliability.[150] DTE also notes that Staff's position on spending increases was initially based on inaccurate data, which Staff subsequently corrected.[151] DTE argues in its reply brief that Staff underestimates the scope of the reliability issues facing DTE.[152]

Staff's brief cites Mr. Mazuchowski's testimony that DTE's requested capital expenditures are significantly above inflation and recent spending increases have not shown an improvement in reliability. Staff also argues that DTE's increased capital expenditures have not reduced O&M expenses. In addition, Staff argues that the comparative information in Exhibit S-9, Schedule 9.4, shows that DTE's projected spending would raise its capital spending levels far above other similarly situated utilities.[153] Staff argues that its use of 10% each year is reasonable and conservative and does not put DTE's spending too far out of line from other similarly situated utilities. In its reply brief, Staff further argues that DTE has not presented a cost-benefit analysis to show how its increased spending will improve reliability or lead to O&M expense savings.[154] Staff addressed Mr. Whitman's testimony that not enough time has elapsed to determine if positive reliability improvements are occurring from previous spending, see 3 Tr 366, by pointing to the history of capital expense increases from 2012 forward

[149] See DTE brief, pages 48-49; DTE reply brief, page 36.
[150] See DTE brief, page 49, citing Whitman, 3 Tr 352-55, 370, 376.
[151] See DTE brief, page 48 at n 45.
[152] See DTE reply brief, pages 36-37.
[153] See Staff brief, pages 17-19.
[154] See Staff reply brief, pages 5-6.

shown in Exhibit S-9, Schedule 9.3, and citing Mr. Mazuchowski's testimony that some impact on reliability should have been observed.[155] Staff also responded to DTE's claims regarding the importance of distribution system capital expenditures:

> DTE Electric explained in its initial brief that distribution operations capital expenditures "are made to connect new customers to the electrical system, improve reliability and strengthen the electrical system, and address load growth and system improvements required to maintain reliable and efficient operation of the electrical system." (DTE Electric's Initial Brief, p 47.) These three items are a basic responsibility of any good utility, and DTE Electric has essentially stated the same premise in its brief in its last rate case. *In re DTE Electric Co*, MPSC Case No. U-17767, DTE Electric's 7/28/15 Brief, p 66. Staff testified in this case that while Staff agrees that additional spending may be necessary, it is also equally necessary to evaluate past spending to determine if the requested level of spending is beneficial to improved customer reliability. (5 TR 1513-1514.) DTE Electric has been increasing Capital spending for several years now and some benefits in reliability should, but have not been demonstrated. (5 TR 1514.) Staff does not have confidence that increasing distribution capital spending at the level DTE Electric proposes will improve reliability feasibly. [156]

Mr. Mazuchoski also recommended that if the Commission approves DTE's capital or O&M expense projections rather than Staff's adjusted projections, the Commission should also adopt a tracking mechanism to reconcile DTE's actual expenditures.[157] Mr. Whitman testified that trackers are unnecessary but, if the Commission approves a tracker for this expense category, it should be a two-way tracker allowing the utility to recover expenses above the amount included in rates.[158] Citing Mr. Whitman's rebuttal testimony,[159] DTE argues that there is no need for trackers because it has consistently spent more than forecasted and approved in rate

[155] See Staff reply brief, pages 4 to 6.
[156] See Staff reply brief, page 5.
[157] See Tr 1516-1517.
[158] See Tr 367-368.
[159] See 3 Tr 367-68, 376.

case filings for both distribution O&M and capital. DTE also argues that any tracker should be a two-way tracker citing the tracker put in place in Case No. U-16472.[160]

This PFD finds, as Staff argues, that DTE has not supported its projected level of capital expenditures. DTE has not presented a cost-benefit analysis for any of its expenditures. Mr. Whitman testified that “Exhibit A-21, Schedule M6 supports that costs and benefits of sectionalizing and operating devices provides the lowest cost per SAIDI minute reduction for projects,”[161] but a review of Exhibit A-21, Schedule M6 shows that it does not contain any evaluation of the design health of DTE’s circuits or establish that DTE is maximizing reliability improvements relative to time and resources. Instead, it is simply an illustration of how improvements in reliability can be made at costs below the cost of replacing an entire circuit or substation.

Indeed, DTE does not project any specific improvements in distribution system reliability tied to its expenditures or tie collection of ratepayer funds to any likely actual outcomes. Instead, DTE uses a few examples to illustrate how reliability may be improved. Mr. Whitman testified in rebuttal that the “System Resilience program is proven to reduce outage duration by over 50% on the circuits to which it is applied and the Repetitive Outage Pocket program is proven to reduce customers experiencing multiple outages by 24% to 30%.”[162] Although he did not provide any citations for these assertions in this portion of his testimony, he appears to be referring to two examples he provided earlier in his testimony. He gave an example of the System Resiliency savings potential in his testimony as follows:

[160] See DTE brief, page 48; DTE reply brief, page 37.
[161] See 3 Tr 320.
[162] See 3 Tr 355.

> Beginning in 2012 and through the end of 2015, 445 circuits have been addressed by this program and its predecessor. As a group, these circuits have shown a 48% all weather SAIDI reduction in post-construction performance relative to their pre-construction three year average from 2012-2013.[163]

This is not "proof" of the effectiveness of the system, without further analysis. For example, we don't know from this example when the trees were trimmed on any of these circuits and what other work might have been performed.

Likewise for the Repetitive Outage Pocket Program, Mr. Whitman testified that the number of customers who experienced four or more outages fell in 2015 by 30% relative to 2014, and similarly the number of customers who experienced five or more outages fell in 2015 by 24% relative to 2014. This is not "proof" that the program was responsible for the reduction since Mr. Whitman's analysis does not consider different levels of storm activity or any other potential explanatory factor. Indeed, a review of the chart Mr. Whitman presented at 3 Tr 288 shows the largest difference between all-weather SAIDI and SAIDI excluding Major Event Days (MEDs) in 2014. In 2014 SAIDI was 793 minutes while the SAIDI excluding MEDs was 189 minutes, a difference of 604 minutes attributable to outages related to major events. Mr. Whitman testified that reliability is significantly influenced by weather and will vary from year to year.[164]

At the same time DTE is arguing it needs funding for its reliability programs, DTE acknowledges that spending for load growth and new business as well as reactive replacements displace proactive investments in system reliability. Mr. Whitman testified to this[165] and his Exhibit A-21, Schedule M8 is intended to illustrate this. Schedule M8

[163] See 3 Tr 322.
[164] See 3 Tr 286; Mr. Wuepper also testified that there were 4 major storms a year on average from 2010 to 2014, while there was only 1 major storm in 2015. See 4 Tr 948.
[165] See 3 Tr 283.

shows that whatever projected capital expense amount the Commission uses in setting rates for DTE, its first priorities are to new business, load growth and relocations, reactive equipment failures replacement, and “other”. It appears to believe this prioritization is appropriate without consideration of any other potential corporate expenditures.

DTE also provided little to no detail regarding how it derived its capital expense projections, although it argues that Mr. Whitman’s analysis is based on detailed analysis and engineering estimates. On this record, Mr. Whitman presented only the detail in Schedule B6.3 of Exhibit A-9, which is a spreadsheet using four main categories: “new business”, “system strengthening and reliability”, “system strengthening blankets”, and “miscellaneous”. Mr. Whitman’s Schedule M8 of Exhibit A-21 attempts to organize the line items of this exhibit into functional categories. The only line items that implement DTE’s reliability efforts as opposed to new business, load growth, and emergency work, are lines 8 (labeled “reliability”) and 19 (labeled “system improvements”). Of those two lines, 99% of the projected capital expenditures are in line 8, reliability.[166] Mr. Whitman testified that line 8 includes the cost for the reliability activities DTE is undertaking, other than tree trimming, as described in “Part IV” of his testimony.[167]

Mr. Whitman identified 6 major efforts DTE is undertaking to improve overall reliability, five of which were included in “Part IV” of his testimony.[168] Excluding the “Enhanced Tree Trimming Program” that he addressed in “Part III”, he identified

[166] New business has six line items, including two for customer advances; load growth and relocations have five line items, reactive equipment failures and replacements have two line items, and there are some miscellaneous line items.
[167] “Line 8 shows the expenditures for projects or programs to maintain or improve reliability. The details of these expenditures were described in the reliability portion of my testimony (Part IV).” See 3 Tr 340.
[168] See 3 Tr 289.

"System Reliability," the "Repetitive Outage Pocket Program," increased maintenance activities for key distribution assets, proactive replacement of aging assets beyond their design life, and last, a focus on improving restoration processes such as "restore-before-repair." These are the programs discussed in "Part IV" of his testimony.[169] The only cost he expressly identified in his testimony in connection with any of these programs is $6.7 million for increased maintenance through breaker, net bank column, and manhole inspections.[170] He testified that "proactive replacement of aging assets" is focused on the replacement of four main asset types: breakers, system cable, underground cable loops, and switchgear.[171]

Only Mr. Coppola's Exhibit AG-17 sheds any light on the reliability costs DTE is projecting. Mr. Coppola's Exhibit AG-17, page 1, contains the first page of Mr. Whitman's workpaper with some expense detail. A review of this page shows that however much confidence DTE may have in these programs, it is not proposing a significant increase in spending on them in 2016 or 2017. This page lists elements of the "System Strengthening and Reliability" costs in lines 8 through 15 of Schedule B6.3. The first 35 lines appear to provide detail for the "Reliability" line item, but "System Resiliency" is a single line item with projected expenses of $53.5 million in 2015, $39.3 million in 2016, and $22.8 million for the first seven months of 2017, and "Repetitive Outage Pocket Program" is also a single line item with projected expenses of $16.7 million in 2015, $16.1 million in 2016, and $10.6 million for the first seven months of 2017. No other supporting detail is provided for these apparently key programs.

---

[169] See 3 Tr 318-330.
[170] See 3 Tr 322.
[171] See 3 Tr 327 330.

Looking at the rest of the page, lines 4 through 7 are for breaker, cable, underground cable, and switchgear replacement, which clearly relates to the "replace aging infrastructure" program Mr. Whitman identified in Part IV of his testimony. This includes cost estimates that are generally projected to decrease from 2015 levels in 2016 and 2017 with the exception of switchgear replacement, which is projected to increase from $0.8 million in 2015 to $1.3 million in 2016 and $5.2 million in the first seven months of 2017. The remainder of the line items are not obviously related to Mr. Whitman's testimony in Part IV, but identify numerous projects that could as easily relate to load growth as reliability and have no additional identifying information. Line 8 is labeled "PTM", which may refer to "pole top maintenance", although Mr. Whitman does not specifically discuss a pole top maintenance program in Part IV of his testimony or the appropriate level of funding for it.

Thus, not only do DTE's testimony and exhibits fail to support the reliability, reasonableness, and prudence of its projected spending, with no cost-benefit analysis, the workpaper Mr. Whitman provided also does not support its projected levels of spending. Instead, it shows over $50 million per year in undetailed, lump sum spending for 2015, 2016, and 2017. In contrast, Staff's analysis is pegged to the average spending levels of other large utilities, and appears rationally related to determining an adequate expense allowance for this category of expenses.

b*. The Attorney General's Recommendations*

The Attorney General recommended the following adjustments to DTE's projected distribution system capital expenditures: exclude the projected contingency allowance of $4.9 million, exclude projected expenses associated with the Gordie Howe

International Bridge and an I-75 construction project, and exclude projected expenditures on a SCADA system expansion. These recommendations are discussed in subsections *i* through *iv*.

i. Contingency Spending

As explained above, Mr. Coppola recommended excluding all contingency estimates from DTE's capital expense projections citing the Commission's prior decisions in Case Nos. U-17767 and U-17735. In DTE's distribution system capital expense projections, DTE included contingency amounts totaling $4.891 million as shown in Exhibit AG-15. Mr. Whitman provided rebuttal regarding the contingency expenditures:

> Contingency is established on large non-routine projects early in their life cycle in case cost increases are experienced due to unforeseen circumstances. This is a common practice in the industry. As engineering analysis is completed, firm material quotes are received and as early construction work progresses those contingency levels are reduced as the contingency is either consumed due to emerging issues or redirected to other new work. All budgeted funds including contingency will be invested *in projects that benefit customers.*[172]

For the reasons discussed in section 2 above, contingency projections are not appropriate for ratemaking.

ii.Gordie Howe International Bridge

Mr. Coppola also recommended that the Commission exclude DTE's $41.8 million projected expenditures associated with the construction of the Gordie Howe International Bridge, as shown in his Exhibit AG-16:

> On line 20 of Exhibit A-9, Schedule B6.3, the Company has included $41,803,000 of capital expenditures for the relocation of power lines and other facilities due to the construction of the Gordie Howe International Bridge and the related plaza and access roads. Exhibit AG-16 includes the

[172] See 3 Tr 374-375.

Company's discovery response supporting these capital expenditures. From Mr. Whitman's direct testimony, it appears that these costs are likely to increase to $85 million through the year 2018. In response to a discovery request, the Company stated that it believes the Windsor-Detroit Bridge Authority ("WBDA") should pay for the majority of the cost of relocating the electric lines and related facilities to accommodate construction of the bridge. Nevertheless, the Company has included these capital expenditures in the forecasted rate base.

It is still unknown if the State of Michigan or some other entity will own the facilities on the United States side of the bridge. Given this uncertainty and to provide the Company with every incentive to recover the cost of relocating its facilities from the parties responsible for building or owning the bridge and adjoin facilities, I recommend that these capital expenditures be excluded from rate base in this rate case. DTE Electric customers should not be solely responsible to pay for costs that will benefit users of the bridge throughout Michigan and outside the State, and even from another nation. Once built, the bridge will charge a toll to recover its capital investment and operating costs. That investment can include the cost of relocating gas facilities owned by DTE Electric.[173]

Regarding the proposed bridge work, Mr. Whitman testified in rebuttal to Mr. Coppola's recommendation as follows:

Q. Why are the GHIB project expenditures required?

A. The Company has been notified by the State of Michigan that it is required to relocate all Company facilities that are in conflict with the construction of the Gordie Howe International Bridge Project. Witness Coppola proposes that the Company ignore this notification and delay the significant amount of work that is required to relocate DTE Electric's facilities in advance of the future bridge construction, which is a critical international project for the rehabilitation of the mid-west region DTE Electric has identified the specific and extensive facilities that must be rerouted and relocated to facilitate the construction of the GHIB. The Witness Coppola's recommendation to reduce capital by $41.8M should be rejected to allow the Company to complete the required work. Postponement will result in unnecessary increased costs to DTE Electric customers.[174]

Citing this testimony, DTE argues in its briefs that it has been notified by the State of Michigan that it is required to relocate all DTE facilities that are in conflict with

[173] See 6 Tr 1807-1808; note that these expenditures are included in a different line of Schedule B6.3.
[174] See Tr 371-372.

the bridge construction and is legally entitled to recover its costs.[175] DTE also contends that Mr. Whitman's 30 years of experience confirms that the Company will not receive funding from the State for the work and delaying that work would only increase its costs, citing his testimony at 3 Tr 386.

This PFD finds that Mr. Coppola's testimony is persuasive. DTE has not established the magnitude or the timing of its projected bridge expenditures. As discussed in connection with the contingency spending issue, DTE can clearly include any reasonable and prudent expenditures in rate base and recover accordingly in future rates. And, as discussed above in section III, DTE is not "entitled" to recover projected rate base expenditures and should have no expectation that the Commission will require ratepayers to prefund uncertain costs. In addition, DTE has not explained what efforts it has undertaken or intends to undertake to safeguard ratepayer interests in light of Mr. Coppola's reasonable concern and in light of DTE's own discovery response indicating it should not be fully responsible for the costs. In that discovery response, DTE was asked to explain why it is not pursuing recovery of costs for the relocation "given that this is a privately owned bridge or owned by an independent authority". It responded:

> DTE Electric objects for the reason that the discovery request requires the Company to render a legal opinion and conclusion regarding the ownership of the Gordie Howe International Bridge (GHIB). Subject to this objection, and without waiving this objection, DTE Electric would answer as follows:
>
> The Company believes the Windsor Detroit Bridge Authority (WDBA) should pay for the majority of relocations of DTE Electric facilities required to accommodate construction of the bridge, however, in light of the

[175] See DTE brief, page 49, DTE reply brief, page 38.

> uncertainty regarding which party will ultimately pay, DTE included the capital expenditures in this case.[176]

Instead of addressing the legal question whether DTE has a claim to cost recovery, and instead of explaining any efforts DTE has undertaken to resolve this question, DTE relies on Mr. Whitman's non-legal generalization as to the likelihood DTE will receive any contributions for the construction. This is not a reliable analysis of DTE's legal rights and remedies in this particular situation, does not show that DTE is fully protecting the ratepayers' interests, and is particularly unhelpful when Mr. Whitman has also acknowledged that he has had no involvement in any of the discussions that may have taken place between DTE and the relevant bridge authorities on this issue.

iii. I-75 Construction

DTE also proposed to recover projected costs associated with an I-75 construction project. In his direct testimony, Mr. Whitman did not expressly address this project. Mr. Coppola recommended excluding the $13.4 million of capital expenditures included in DTE's projected rate base:

> On line 11 of Exhibit A-9, Schedule B6.3, the Company has forecasted $7,304,000 of capital expenditures for 2016 and $6,100,000 for the first seven months of 2017 for the I-75 Modernization. The total of the two amounts is $13,404,000. Exhibit AG-17 includes Company workpaper WPB6.3 (line 50) supporting these amounts. In discovery, I requested the Company to explain the reason for the forecasted expenditures and justify why they were necessary and essential to be incurred in those years. The Company's response, included on page 3 of Exhibit AG-17, states that "Through discussions with the Michigan Department of Transportation, the Company understands that major efforts are planned for 2016 and 2017 to improve the physical structure of the bridges crossing I-75." The Company has therefore estimated certain costs to replace or upgrade its facilities based on its understanding of the work that may take place.
>
> The Company has not presented any specific work plan or schedule of when this work and expenditures will take place. The timing of the

[176] See Exhibit AG-16.

> expenditures seems to be based on discussions and general understanding on the part of the Company of which bridges may be rehabilitated. These planned expenditures may or may not occur within the planned periods forecasted. The timing and level of work is uncertain. Without a definite schedule and work plan, it is not possible to support inclusion of the forecasted capital expenditures in rate base.[177]

Regarding the I-75 construction project, Mr. Whitman testified in rebuttal to Mr. Coppola's recommendation as follows:

> Plans have been released from the Michigan Department of Transportation, detailing the areas of expressway they plan to widen and the bridges that will be rebuilt on I-75. It has been determined that 23 road crossing will be impacted over all phases of construction. Immediate requirements involving heavy construction, includes relocating underground (UG) conduit containing multiple circuits. This work is extremely labor intensive and requires a large lead time to complete the necessary work. Witness Coppola recommends reducing capital expenditures by $13.4 million for this project due to lack of specific work plans and schedule. Witness Coppola's argument that specific plans are not provided is unreasonable, as specific details are not usually shared in these rate proceedings. The Company has received the typical notification from the State of Michigan on this project and needs to comply with the relocation requirements in a timely fashion, as to not delay the project or cause increased costs. The Company is obligated to complete the work required by the State of Michigan to address the deterioration of Michigan's road infrastructure. Any such position should be rejected.[178]

On cross-examination, Mr. Whitman again acknowledged he had not provided details regarding the proposed expenditures and also indicated that he did not have a clear understanding of the timeframe within which the work would be done:

> Q Did you provide any work plans or schedule in your rebuttal testimony to support the level and timing of these expenditures?
>
> A I provided some general high-level description of the project, what it involved that we know right now.
>
> Q And where is that in your rebuttal?

[177] See 6 Tr 1809-1810.
[178] See 3 Tr 373.

A Page 22 -- or line 22, page -- I'm sorry. I've got to find it in the right -- I've got to adjust here, so I'm sorry, just take me a minute. Line 13, "It has been determined that 23 road crossings will be impacted over all phases of construction." Immediate requirements involving heavy construction, issuing, relocating underground conduit, conducting multiple circuit transfers, and it's labor intensive.

Q O.K. And is that the extent of the work plans and schedules to support your expenditure for this I-75 Modernization project?

A That's correct. It's not, that's about the level that we typically provide on a project like this in a rate case.

Q Now, do you have more information about the specifics on the work plan and schedules but just haven't provided it yet, or you just don't have any?

A We have from the State of Michigan the timeline of the entire project and various phases of that project and the year in which they plan to do it. They typically give us eight to ten months lead time with specific plans. We haven't received those specific plans for the areas that we were looking, but we to know what pieces were in the way.

Q And have you provided any -- so the information that the State of Michigan has given you is just that there are road crossings that will be impacted and there might be some heavy construction?

A They didn't give us information on heavy construction, that was our determination. They gave us information on the scope of project that -- the area of the expressway involved and the times, approximate years of when the construction would take place.

Q And did you provide that information in your testimony?

A No.

Q All right. And when do you expect to get the information
from the State of Michigan on the more specific information?

A The first major conflict is, they have scheduled for somewhere in 2018, we don't know when, so I would expect that information to be coming very shortly.

Q And when you say very shortly, month?

A I can't predict when they're going to give it to us; typically I said eight to ten months in advance when of when they do the work.

Q So if it's 2018, wouldn't that be sometime in '17, then?
A Somewhere in that early -- or late '16, early '17.

Q When in 2018 did you say?

A I didn't say. Could be January.

Q O.K.

A That's why we haven't gotten that information yet.[179]

In its brief, DTE acknowledges the Attorney General's concern that DTE does not have specific work plans or a specific schedule, but dismisses the concern rather than address it. DTE argues that Mr. Coppola's recommendation is "unreasonably based on an alleged lack of specific work plans and schedule."[180] In this regard, DTE argues that the company received "the typical notification" from the State of Michigan and is obligated to complete the work required. DTE then argues that it "has a right to recover its costs,"[181] further contending in its reply brief that the Attorney General is "as a representative of the State, attempting to penalize DTE Electric for allegedly insufficient information provided by the State."[182] In a footnote, DTE also cites the 14th Amendment to the U.S. Constitution and Article 1, section 17 of the Michigan Constitution of 1963.

This PFD finds that the Attorney General is correct: DTE has failed to support the magnitude and timing of its projected expenditures associated with the I-75 project. The Attorney General is not "penalizing" DTE for a deficiency in the notice by the State, but recognizing the reality that DTE does not know exactly when it will perform the work and

179 See Whitman, 3 Tr 392-394.
180 See DTE brief, pages 49-50.
181 See DTE brief, pages 49-50.
182 See DTE reply brief, pages 38-39.

has not presented a reliable cost estimate for that work. As discussed in connection with the contingency spending issue in section V.2 above, DTE can clearly include any reasonable and prudent expenditures in rate base and recover accordingly in future rate cases. And, as discussed above in section III, DTE is not "entitled" to recover projected rate base expenditures and should have no expectation that the Commission will require ratepayers to prefund uncertain costs.

iv. SCADA

Mr. Coppola recommended a $10.49 million reduction in capital expenditures projected for an expansion of DTE's SCADA system:

> On line 8 of Exhibit A-9, Schedule B6.3, the Company has forecasted $6,591,000 of capital expenditures for 2016 and $3,899,000 for the first seven months of 2017 for SCADA monitoring. Exhibit AG-17 includes Company workpaper WPB6.3 (line 29) supporting these amounts. In discovery, I requested the Company to explain the reason for the forecasted expenditures and justify why they were necessary and essential to be incurred in those years. The Company's response, included in Exhibit AG-17, basically explains how the automated SCADA system works. It also states that the installation of the equipment would replace manual reading of power measurement and provide more timely alerts of faults or disturbances. Although these are nice improvements, the Company has operated well without having these locations automated for many years.
>
> The key questions then are why invest $10,490,000 now, between 2016 and the 7-months ending July 2017, and do the financial benefits exceed the cost of investment. If currently there are large inefficiencies or problems with the current operation at the targeted locations, then a cost/benefit analysis should easily justify the investment. The Company has not made a convincing case. In fact, other than the discovery response, the Company has not presented any financial justification or compelling evidence to support the expenditures as necessary and essential to its continued operation of the distribution system.[183]

[183] See 6 Tr 1808-1809.

In rebuttal, Mr. Whitman testified:

> These expenditures are necessary to provide fault indication and circuit load data. The load data is used to more accurately determine the load distribution at substations and circuits for planning future maintenance, repairs, upgrades, circuit consolidation and investment in the DTE electric distribution system. Currently many of these locations have limited measurement capability or must be manually read on a periodic basis. The new monitoring equipment provides more visibility into the system condition through loading information as well as the ability to act as fault indicating devices. As part of overall efforts to improve system reliability, the fault indication allows for more rapid notification of disturbances and outages and more accurate response for restoration and repair. The Company has determined that approximately 60% percent of its system is currently monitored by SCADA devices, and that is well below best in class peer utilities which are typically monitored at 100% SCADA.[184]

DTE argues in its brief that the expenditures are necessary to provide fault indication to improve system reliability and circuit load data that will be used for maintenance, repairs, upgrades, circuit consolidation and investment in the Company's distribution system, which DTE maintains is 40% below its peer utilities, citing Mr. Whitman's testimony at 3 Tr 374 and 377.[185] DTE argues: "The AG's suggestion that DTE Electric should have submitted additional 'financial justification or compelling evidence' lacks merit since even the AG does not indicate any reason to not make the expenditures and the value of improved restoration and repairs is self-evident."[186]

While the Attorney General is correct that DTE did not provide a cost-benefit analysis of this expenditure, the Attorney General does not challenge the cost estimate and does not challenge DTE's assertion that its peer utilities all have such systems in place for 100% of their service territory. This PFD finds that DTE's plan to expand installation of a SCADA system is reasonable and given the relative magnitude of

---

[184] See 3 Tr 374.
[185] See DTE brief, page 50, DTE reply brief, page 39.
[186] See DTE reply brief, page 39.

dollars involved ($10.5 million through the 2016-2017 test year) and the deficiency in DTE's system currently compared to its peers, this PFD finds that DTE will indeed complete the installation. Thus, this PFD finds that it is reasonable to include the projected SCADA costs in the projected rate base.

c. *MEC/SC/NRDC*

Mr. Jester testified that DTE has not considered opportunities to improve the efficiency of its system by reducing line losses in connection with the substantial work the utility is proposing to undertake on its distribution system. He testified that the installation of AMI facilitates improvements in several key areas. Mr. Jester identified eight specific practices that should be examined: metering at intermediate points in the distribution system; improving the balance between phases in three-phase circuits; right-sizing transformers based on site-specific AMI data; dynamic voltage and power factor control; conservation voltage reduction to reduce load at high times; remote monitoring and as-needed maintenance of line equipment; selective distribution system improvements to address grid locations with high losses; and deploying efficiency programs, demand response, or other programs to reduce distribution load at high-load times or in locations with high system loss rates.[187] He explained the value of AMI data, including lengthy explanations of how AMI data can be used in phase balancing, transformer load balancing, and dynamic voltage and power factor control.[188]

Mr. Jester recommended that in granting rate relief to DTE in this case, the Commission also require DTE to evaluate these opportunities and provide a report to

[187] See 5 Tr 1617-1618.
[188] See 5 Tr 1620-1634.

the Commission prior to or concurrent with its next rate case filing.[189] He cited DTE's discovery response in Exhibit MEC-4 indicating that DTE has not evaluated the potential to reduce system losses from the projected distribution operations capital spending:

> DTEE's reliability is degrading and consistently ranks in the fourth quartile among peer utilities with respect to standard measures of reliability. DTEE must continue to focus on the reliability of the electric system to benefit the Company's customers. For this reason, distribution capital spending is focused on addressing reliability, aging infrastructure, connecting customers, and relocations. While some reliability projects and the replacement of aging electric equipment will have a small positive impact on system losses, this is not the main focus of the distribution capital spending.[190]

Mr. Whitman's rebuttal testimony similarly stated:

> The Company does not support requesting additional funds to develop a specific line loss program. Distribution Operations is focused on improving reliability performance, addressing aging infrastructure, and enhancing distribution system technology to improve the quality of service to the Company's customers. The Company is already taking steps to minimize system losses as part of normal engineering processes and analysis. This includes properly sizing transformers maintaining load balancing on distribution circuits, and installing voltage correction devices, such as capacitors and regulators. Additionally the Company is applying Smart Technology such as SCADA and remote monitoring to improve the efficiency of the analysis and corrective action process.[191]

In their brief, MEC/SC/NRDC argue that although DTE is planning to spend a substantial amount of money on its distribution system in 2016 and 2017, it does not project any improvement in distribution system efficiency. Citing Mr. Jester's testimony and Exhibit MEC-4, MEC/SC/NRDC argue that DTE should evaluate the potential for reduction in system losses resulting from the projected distribution spending. MEC/SC/NRDC quote the following language from the Commission's November 19,

---

[189] See 5 Tr 1616-1634.
[190] See Exhibit MEC-4.
[191] See 3 Tr 375.

2015 order in Consumers Energy's last rate case, Case No. U-17735, also cited by Mr. Jester:

> Notwithstanding, the Commission recognizes the importance of understanding potential opportunities to reduce energy waste through the mitigation of line losses in the event such opportunities are cost-effective relative to other investments. Given that the functioning of the grid and replacement of aging distribution infrastructure will likely be of ever increasing importance in the coming years with the advent of emerging technologies, the Commission finds it is important to examine distribution planning in a holistic manner and base investment decisions on strong analytical support of the costs and benefits. The Commission therefore directs the Staff to engage with stakeholders on the process going forward, to educate and enhance understanding of this complex issue.

MEC/SC/NRDC argue that the most cost-effective way to reduce system losses is holistically, as part of a large-scale distribution capital spending program, and thus urge that DTE should be required to demonstrate that it will exercise appropriate diligence in ensuring that the combined costs of system losses and available mitigation measures have been or are being minimized.[192]

MECSC/NRDC also address Mr. Whitman's rebuttal testimony indicating that the company is already taking steps to minimize system losses as part of normal engineering processes. They argue that these steps are insufficient, characterizing them as "simply standard (albeit modern) engineering practices" that do not reflect AMI and other innovative technological opportunities.[193] MEC/SC/NRDC also argue that Mr. Whitman did not explain why the company is not proposing any of the measures identified by Mr. Jester, and did not explain the contradiction between Mr. Whitman's testimony that the company is taking steps to minimize losses and DTE's discovery response indicating that the company has not evaluated the potential for reduction in

[192] See MEC/SC/NRDC brief, page 30.
[193] See MEC/SC/NRDC brief, page 32.

system losses resulting from the projected distribution capital spending and has no intent to undertake such an evaluation.[194]

In its brief, DTE argues that Mr. Jester's proposal would require additional capital that is unnecessary because the company is already taking steps to minimize system losses as part of normal engineering process and analyses, including properly sizing transformers, maintaining load balancing on distribution circuits, and installing voltage correction devices such as capacitors and regulators. DTE identifies the SCADA system as part of these efforts, citing Mr. Whitman's testimony that it uses "Smart Technology".[195] In its reply brief, DTE further argues that MEC/NRDC/SC acknowledged that the alleged potential benefits are speculative, citing their initial brief at page 40, and thus can provide no basis for DTE to develop a comprehensive plan and report.[196]

This PFD finds that MEC/SC/NRDC have raised an issue that is appropriate for further study but not appropriate for a revenue adjustment in this case. While the Commission could require DTE to provide a complete analysis of the opportunities to increase distribution system efficiency utilizing its AMI infrastructure, the Commission's decision in Case No. U-17735, quoted above, acknowledged that these issues require ongoing evaluation, and expressed a preference for a holistic evaluation involving Staff and stakeholders. Since Mr. Whitman testified that DTE is taking steps to minimize system losses as part of its normal engineering processes and analysis, including properly sizing transformers, maintaining load balancing on distribution circuits, and

[194] See MEC/SC/NRDC brief, page 32.
[195] See DTE brief, pages 50-51, citing Whitman, 3 Tr 375, 377.
[196] See DTE reply brief, pages 40-41.

installing voltage correction devices, the Commission should nonetheless expect DTE to explain those efforts and any other such efforts in its next rate case.

d*. Discussion*

As noted above, Staff's and the Attorney General's recommendations regarding distribution system capital expenditures are difficult to harmonize. On the one hand, Staff has established that DTE has not justified its projected 2016 and 2017 projected capital expenditures and reasonably proposed limiting to 10% the annual increase in capital expenditures to be funded by ratepayers in this case. On the other hand, the Attorney General has established specific line items of projected expenditure that DTE has not justified, including contingency spending and potential construction projects for the Gordie Howe International Bridge and I-75. These parties do not address each other's recommendations. Based on the record, this PFD finds that it would be reasonable for the Commission to adopt either the Staff's more generalized adjustment or the three specific adjustments recommended by the Attorney General. Both sets of adjustments have a similar impact on the revenue requirement.[197]

If the Commission adopts the more specific adjustments recommended by the Attorney General, this PFD further recommends that it adopt a form of the tracker recommended by Staff. A key concern raised by DTE's evidentiary presentation in this case is that DTE finds it acceptable to displace spending on reliability projects for which it received ratepayer funding with spending for new business and load growth as well emergency repair.[198] Also, a review of Mr. Whitman's Schedule R2 of Exhibit A-28

[197] This PFD estimates that adopting the contingency adjustment and adjustments related to the Gordie Howe International Bridge and I-75 projects in lieu of Staff's adjustment would reduce the revenue requirement by an additional $463,000.
[198] See 3 Tr 289-293.

shows that although DTE's 2015 actual distribution capital spending was $10 million more in 2015 than it projected in Case No. U-17767, the spending for the "system strengthening and reliability" line items were $30 million below the rate case projection while "new business" spending was $30 million more than projected. Mr. Whitman's schedule M8 of Exhibit A-21 also shows DTE's view that its ratepayer funding for distribution operations is fungible, essentially stating that DTE will spend all distribution operations capital amounts included in rates in this case on load growth and new business before spending it on reliability programs.

This prioritization is despite DTE's acknowledgement that its performance metrics are fourth-quartile poor and may get worse should DTE displace proactive reliability spending with additional spending on load growth and new business. In his direct testimony, Mr. Whitman presented a chart showing DTE's performance as measured by both SAIDI and SAIDI excluding MEDs, over the time period 2005 to 2015, with metrics in the fourth quartile since 2011. He testified that this data clearly shows a negative trend and further stated: "This trend is expected to grow if the Company continues to address outages using primarily reactive processes instead of proactive approaches."[199]

DTE acknowledges that it has a duty to provide safe and reliable service to its customers. Correspondingly, DTE has an obligation to raise the necessary capital to meet its ongoing obligations without regard to whether the Commission and ratepayers have already included those obligations in DTE's rate base and rates. Also, DTE should not have difficulty raising capital for new business and load growth without reliance on ratepayer prefunding given that new business and load growth increase the

[199] See 3 Tr 287.

utility's revenues. It should be noted that DTE suffers virtually no "regulatory lag," self-implementing rates in this case one month after the end of the projected test year it used in Case No. U-17767. Thus, it is an unexplained mystery why DTE views its distribution operations capital expense funding as a single general fund to spend without regard to the reasons it obtained the funding. Nonetheless, given the utility's viewpoint, this PFD recommends that the Commission take steps to provide greater accountability for the utility's distribution system performance.

As noted above, DTE opposes a tracker and in the alternative wants a two-way tracker. First, this PFD does not recommend that the Commission adopt an open-ended two-way tracker, which is essentially encouraging DTE to spend money on its distribution system without meaningful ratepayer protections. As discussed above, DTE has not established it has a clear and comprehensible plan to significantly improve its distribution system performance. Instead, this PFD recommends that the Commission adopt a one-way tracker only for the "reliability" expenditure portion of DTE's capital expense projection, as set forth in lines 2 through 34 of Exhibit AG-17, page 1. DTE would need to show it has reasonably and prudently spent up to the projected amounts on projects meeting the descriptions provided in "Part IV" of Mr. Whitman's testimony.

Whether or not this Commission chooses to adopt a reliability expenditure tracker, in recognition of the significant concern raised by DTE's poor system performance metrics, this PFD also recommends some additional Commission oversight. Specifically, this PFD recommends that the Commission initiate a proceeding on its own motion to investigate the potential for DTE to improve its distribution system reliability. This investigation could consider: the costs and benefits of DTE's distribution system maintenance programs; whether DTE has an effective capital investment strategy; what metrics other than overall system performance metrics should be considered, and what other analytical tools may be useful to evaluate DTE's distribution system capital investments; and the identification of ratemaking mechanisms or other regulatory responses that would ensure that funds allocated for reliability improvements are actual spent on those improvements. Consistent with the discussion in subsection c above, this inquiry could also be broadened to consider the contributions AMI meters can make to system reliability and efficiency, as discussed above, although the Commission's order in Case No. U-17735 appears to prefer a less formal context for that review.

6. <u>Community Lighting (line 8 of Exhibit A-9, Schedule B6)</u>

Mr. Johnston presented testimony in support of projected capital expenditures for the community lighting program. He also presented Schedule B6.4 showing the costs for "new installations and replacements" and "series conversion" from 2014 through the projected test year with annual expenses for 2015 and 2016 totaling approximately $12.7 million each year. No party objected to these expense projections, and this PFD recommends that they be incorporated in the projected rate base and revenue requirement calculations.

7. <u>Corporate Staff Group (line 9 of Exhibit A-9, Schedule B6)</u>

Under the category of Corporate Staff Group capital expenditures projected for the period from the historical test year through the projected test year, DTE includes a total of approximately $536.8 million in spending, as shown on line 9 of Schedule B6, with additional detail in Schedule B6.5 of Exhibit A-9. Ms. Uzenski provided testimony in support of these proposed expenditures.

Staff recommended an adjustment to the projected expenditures for "shared IT infrastructure" while the Attorney General recommended several adjustments to this line item and, in addition, recommended adjustments to the following other line items: facilities renovation, service center optimization, facilities—construction and upgrade, as well as the removal of contingency expenditures. Several IT-related capital expense projections are discussed in section a below while the Attorney General's recommendations regarding the other line items of Schedule B6.5 are discussed in sections b through f.

a. *contingency*

The Attorney General recommended excluding contingency expenditures from this category of $.8 million, per Exhibit AG-15. DTE did not address this adjustment specifically, in addition to stating its general objections to the exclusion of contingency amounts. Also, it did not argue these adjustments were duplicative of any other adjustment.

b. *Information Technology (IT)*

Several of the line items on Schedule B6.5 of Exhibit A-9 are labeled as "IT" or software. Staff recommended an adjustment to the "shared IT" spending projections in line 5 while the Attorney General recommended adjustments to this line item and to the "reliability IT" and "Enterprise Software" projects in lines 4 and 9 of this schedule.

i. Staff Adjustment

Staff recommended a $3.1 million adjustment to shared IT spending, based on Staff's analysis of the historical variability of expenditures in this category. Mr. Matthews explained that Staff's adjustment reduces the capital expense projection for the telecommunications component of this category to the most recent three-year average.[200] In its brief, Staff argues that averaging the last three years brings a more accurate and stable cost projection.[201]

In her rebuttal, Ms. Uzenski testified that Staff's recommendation to use a three-year average to forecast projected capital expenditures on telecommunications equipment is inappropriate because it includes unusually low expenditures in 2014 and 2015 due to capital constraints and the need to fund more urgent projects. She testified that beginning in 2016, DTE is increasing its investment in telecom as part of a five-year plan to address gaining infrastructure and approve operational effectiveness and to support data analytics for new technology including AMI.[202] DTE relies on this testimony in its briefs.[203]

Staff addressed Ms. Uzenski's rebuttal testimony in its initial brief, not disputing her testimony that DTE spend less than it wanted in 2014 and 2015, but arguing that the company's expenditures in this category also show volatility in 2012 and 2013. Staff also argues that the company's acknowledged reluctance to spend money in this area makes its projection unreliable.

This PFD finds that Staff's recommended adjustment to the projected telecommunications infrastructure spending is reasonable based on DTE's historic

[200] See Mr. Matthews's testimony at 5 Tr 1502-1503; Exhibit A-9, Schedule B6.5, line 5; Exhibit S-10.6.
[201] See Staff brief, pages 13-15.
[202] See 4 Tr 858-859.
[203] See DTE brief, pages 69-70; DTE reply brief, pages 55-56.

spending, appropriately balancing the ratepayers' interests in not paying a return on and of investment that might not be made with DTE's interest in prefunding a projected rate base. In its next rate case, DTE can still seek to include in rate base reasonable and prudent expenditures that are actually made.

ii. Attorney General Adjustments

The Attorney General recommended three adjustments to capital expenditures involving IT addressing a total of $15.5 million in projected expenditures. First, he objected to DTE's projected spending of $3.2 million in 2016 and the first seven months of 2017 to develop a "landlord tool". Mr. Coppola testified that total spending on this project is expected to continue beyond the test year at additional cost:

> The Company did not explain why this tool and this functionality is critically needed and how many landlords may benefit. My assessment is that landlords are a very small fraction of the customer base. To spend millions of dollars to provide a tool to a small set of customers is inappropriate. The larger customer population should not pay for functionality or benefits accruing to only a small group of customers.[204]

In rebuttal testimony, Ms. Uzenski explained why she disputed the Attorney General's recommendation:

> The customer service tool, projected to cost $3.2 million, is a Landlord Utility Manager Portal allowing landlords to interface with the new Customer 360 system via the web. DTE works with approximately 60,000 landlord/property managers who manage about 561,000 sites. The tool will allow them to manage multiple accounts on-line and use self-service functionality to obtain the status of service for their properties. The tool will not only make landlord interactions with the Company more efficient from their perspective, it should reduce the number of phone calls coming into our call center, potentially lowering future operating expenses by over $1 million annually.[205]

[204] See 6 Tr 1831.
[205] See 4 Tr 859.

In its briefs, DTE emphasizes Ms. Uzenski's testimony and the statistics she presented.[206]

Second, Mr. Coppola looked at projected expenditures for "Reliability IT". Mr. Coppola reviewed information provided by DTE in response to a Staff audit request seeking a list of all electric reliability projects, Exhibit AG-25. He objected to the company's $9.1 million projection for 2017:

> [T]he company provided detailed lists of projects for the years 2014, 2015 and 2016. With regard to the 7 months ending July 2017, the Company repeated the same list of projects presented for 2016, with 2016 completion dates, and simply calculated 7/12th of those capital expenditures as being applicable for the 7-month period of 2017. . . . This is not an acceptable forecasting approach for inclusion of $9,120,000 of capital expenditures in rate base. The approach taken by the Company indicates that the Company has no specific plans as to how much and in what manner it will invest on reliability projects during the first 7 months of 2017. Instead, it has simply "thrown in" some dollars for inclusion in the projected rate base.[207]

Similarly, Mr. Coppola's third objection to the IT expense projections focused on the company's projected spending in "Enterprise Software" for 2017. Also citing Exhibit AG-25, he testified:

> The Company's response . . . stated that 2017 project detail has not been developed. Again, the approach taken by the Company indicates that the Company has not specific plans as to how much and in what manner it will invest on enterprise software projects during the first 7 months of 2017. Instead, it has simply thrown in some dollars for inclusion in the projected rate base. The lack of specificity and detailed support invalidates the forecasted amount of capital expenditures for the 7 months ending July 2017. I recommend that the Commission remove the $3,262,000 in forecasted capital expenditures.[208]

In her rebuttal testimony, Ms. Uzenski asserted that the rate case forecast for reliability and enterprise software was "based on the recurring need for investments in

[206] See DTE brief, page 70; DTE reply brief, pages 56-57.
[207] See 6 Tr 1831-1832.
[208] See 6 Tr 1832-1833.

information technology," and further testified that: "The review and approval process of 2017 expenditures began on June 19, 2016 and is still in progress." She presented a rebuttal exhibit listing "recently approved projects supporting the Company's original request for 2017 expenditures."[209] In its briefs, DTE characterizes its original forecast as based on a "recurring need for IT investments."[210] DTE also reiterates, as it does in connection with the contingency spending, that it is committed to spending all of the forecast 2017 dollars.[211]

This PFD recommends that the Commission adopt the Attorney General's requested adjustments regarding the landlord tool, based on the record evidence the landlord tool will not be completed in this test year. Ms. Uzenski testified on cross-examination that DTE anticipated spending an additional $0.8 million after the end of projected test year. She expects the landlord tool to go into service sometime in 2017 after Customer 360 goes live.[212] DTE has designed the tool for approximately 60,000 landlords or property managers who manage about 561,000 properties, an average of over 9 properties per landlord.[213] The $4 million projected cost for this tool is thus approximately $66 per landlord. While DTE projects potential cost savings with this tool, it also projects greater efficiency for those landlords who use the tool.[214] Also based on the record, DTE believes the landlord tool may save as much as $1 million per year by reducing phone calls but does not expect any savings until after the test year. This PFD thus recommends that the Commission defer including projected landlord tool

[209] See 4 Tr 860.
[210] DTE brief, pages 70-71.
[211] See DTE brief, pages 70-71, reply brief, page 57.
[212] See 4 Tr 887-888.
[213] See 4 Tr 859.
[214] See 4 Tr 859.

costs in rate base until the project is completed and in service. In the company's next case in which it seeks to include these costs in rate base, it should also address whether a nominal charge to landlords who use the tool is appropriate.

Regarding the reliability and Enterprise software projections, this PFD finds Mr. Coppola's testimony persuasive that DTE did not support its 2017 projections in its filing, and agrees that DTE cannot simply reserve capital expense dollars in its rate case filing as a placeholder and months later develop a plan as to how to spend those dollars. Any additional capital spending beyond the 2016 capital expense projections, which have not been challenged, can be reviewed for reasonableness and prudence in DTE's next rate case.

c. Facilities Renovation (line 12 of Exhibit A-9,Schedule B6.5)

The Attorney General also makes several recommendations regarding expenditures for various DTE facilities, presented in Schedule B6.5, lines 12, 13, 14, and 16. Focusing on the "facilities renovation" expenditures presented in line 12 of Schedule B6.5, Mr. Coppola presented Exhibit AG-26 to show the detail DTE provided in discovery regarding this line item, and recommended that the Commission exclude a total of $18.5 million of these expenditures. First, he recommended that the Commission exclude $7 million in 2015 spending for a gym and a clinic in DTE's main office building.

Mr. Coppola testified:

> From the information provided by the Company, it is unknown why the Company believes it needs to invest $7 million in such facilities and why utility customers should pay for it. Although a gym and a clinic are nice prerequisites for employees they are not critical or essential to the operation of the utility business, particularly at a time when other capital

expenditures are rising at a double digit rate and customer rates are escalating almost annually at nearly the same percentage.[215]

Second, he recommended that the Commission exclude $11.5 million in capital expenditures projected for six renovations projects in the first seven months of 2017:

> Additionally, the schedule of projects in Exhibit AG-26 shows that for 2017 the Company has listed 6 renovation projects and each of them is for exactly the same amount of $3,300,000. It is peculiar that each project is exactly the same amount. For the 7 month ending July 2017 the Company has forecasted $11,550,000 in capital expenditures for facilities renovation. This appears to be 7/12th of the sum of the 6 projects for the year. Once again, the approach taken by the Company indicates 1 that the Company has no specific plans as to how much and in what manner it will invest in facilities renovation projects during the first 7 months of 2017. Instead, it has simply "thrown in" some dollars for inclusion in the projected rate base. The lack of specificity and support invalidates the forecasted amount of capital expenditures for the 7 months ending July 2017. I recommend that the Commission remove the $11,550,000 in forecasted capital expenditures.[216]

Ms. Uzenski also provided rebuttal testimony in response to Mr. Coppola's recommendations. Regarding the gym and clinic, she testified:

> The DTE Performance Center (gym and clinic) was constructed to support the Company's commitment to health and safety and to increase productivity. DTE's downtown campus previously did not have onsite clinic services so employees had to travel elsewhere for new hire physicals, primary, urgent, and episodic care, blood pressure checks, physical therapy, prescription delivery, occupational injury treatment and annual OSHA medical surveillance requirements. Having a clinic on site should reduce lost work time associated with employees leaving the campus for these services. The clinic also provides first responders a staging place to respond to workplace accidents and all medical emergencies. The Performance Center promotes physical activity and employee fitness which may reduce lost work days from illness or injury. In summary, the Performance Center enhances the health and productivity of our work force and a productive work force is required to provide effective utility operations and quality customer service. Therefore, the AG's proposal to disallow recovery of the Performance Center should be rejected.[217]

---

[215] See 6 Tr 1833.
[216] See 6 Tr 1833-1834.
[217] See 4 Tr 861.

Regarding the 2017 facilities renovation, she testified:

> As described in my direct testimony, the Facilities Renovation project began in 2012 and replaces old infrastructure and out of date facilities, brings spaces up to code, and reduces the average floor space per employee. The overall project is broken down into sub-projects for different locations and even individual floors within some locations. The forecast assumed certain sub-projects would be worked on during 2017. As shown on Exhibit AG-26, page 2 of 3, the Company provided the AG with a breakdown of the locations expected to be renovated during 2017. Furthermore, I have provided an updated estimate for the sub-projects on Rebuttal Exhibit A-30, Schedule T4, lines 1 through 11. The final detailed budgets for 2017 are still under development but the schedule does demonstrate that the locations originally identified for work in 2017 are still in the plan, and the total cost is close to our filed position.[218]

DTE argues that the gym and clinic are prudent investments that support the health, safety and well-being of DTE employees, and that reduce losses in productive work hours related to injuries, illnesses, and traveling to offsite medical providers, citing 4 Tr 861.[219] This PFD agrees that DTE has a reasonable basis for these expenditures, and unlike mere projections, the gym and clinic have already been completed. While they may be viewed as amenities for the employees in that office building, that does not make the expenditures unreasonable or imprudent.

Regarding the 2017 facilities renovation projections, DTE disputes that the request for funding was simply “thrown in” to its rate case request, arguing that it provided a breakdown of the locations to be renovated in 2017, as shown in Exhibit AG-26. DTE also provided an updated estimate in Exhibit A-30 to show that the locations originally identified for 2017 are part of the current plan and the current cost

[218] See 4 Tr 862.
[219] See DTE brief, page 71; reply brief page 58.

estimates are close to the company's initial projection.[220] This PFD finds that DTE's explanation that these projections were part of a specific ongoing project that began in 2012 explains what would otherwise appear to be merely a placeholder as discussed above. On this basis, it is reasonable to include the projected 2017 expenditures in rate base.

d. *Service Center Optimization (line 13 of Exhibit A-9, Schedule B6.5)*

The Attorney General also recommended removing $16.7 million in projected service center optimization expenditures for 2017 as unsupported:

> For the 7 months ending July 2017, the Company has projected $16,683,000 in capital expenditures. The source of this amount is unknown. The schedule that the Company provided to support the 2014 through 2017 forecast, and included in Exhibit AG-26, shows that for the entire year the Company has forecasted $35.5 million for modernization of 5 customer service centers. This forecast seems to be a "ball park" estimate with no specificity. Taking 7/12th of the $35.5 million results in an amount significantly different than the amount projected for the 7 months of 2017. Without specific support for this number is not possible to accept the forecast.[221]

Ms. Uzenski also addressed this testimony in rebuttal:

> Witness Coppola characterizes the Company's 2017 cost projection for optimizing the centers as a "ball park" estimate and recommends the entire amount of the 2017 projection, $16.7 million, be disallowed. One factor that appears to have contributed to his conclusion is that in response to a discovery question, the Company provided an updated 2017 *calendar* year forecast for this item of $35.5 million instead of the original projection. Our original projection for *calendar* year 2017 was $28.6 million, which was the basis for the amount for the period ending July 31, 2017 of $16.7 million (7/12 of $28.6).[222]

She then explained the specific basis for the company's projection:

> As shown on Exhibit AG-26, page 2 of 3, the Company provided the AG with a breakdown of the locations impacted by this initiative. As mentioned

[220] DTE also cites 4 Tr 851, 861-862, 893.
[221] See 6 Tr 1834.
[222] See 4 Tr 862-863.

> in my direct testimony, the Service Center Optimization initiative will consolidate facilities in Pontiac and in Mt. Clemens to realize savings opportunities, as well as increase efficiency within the sites. The Company will also update and optimize the space at the Warren Service Center. In addition, I have provided an updated estimate for the project on Rebuttal Exhibit A-30, Schedule T4, lines 13 through 18. As already mentioned, the final detailed budgets for 2017 are still under development but the schedule does demonstrate that the locations originally identified for work in 2017 are still in the plan; and in fact, the total cost estimate exceeds the amount reflected in the Company's proposed revenue requirement.[223]

DTE relies on this testimony in its brief and reply.[224] The Attorney General does not expressly address this testimony and this PFD finds that Ms. Uzenski has satisfactorily explained that DTE had specific plans to renovate the service centers prior to filing its rate case application, although its cost estimates were not precise. On this basis, this PFD recommends that the Commission reject the Attorney General's proposed adjustment.

e*. Other Miscellaneous (line 16 of Schedule B6.5)*

The Attorney General also recommended excluding $3.9 million in expenditures related to Federal Park Place included in line 16 of Schedule B6.5. In her direct testimony, Ms. Uzenski testified that line 16 includes costs related to the Federal Park Place parking lot used for utility equipment and vehicles and a crime deterrence initiative that uses devices such as security cameras to create safer environment for employees that walk within the company's headquarters neighborhood in downtown Detroit.[225]

Mr. Coppola cited the Commission's decision in Case No. U-17767 that capital expenditures for the acquisition and development of land known as the Federal Park

[223] See 4 Tr 863.
[224] See DTE brief, page 72; reply brief, page 58.
[225] See 4 Tr 833-834.

Place should be excluded from rate base. Acknowledging that the company now wants to include $3.9 million in rate base for this property as a place to store equipment, Mr. Coppola expressed skepticism that DTE truly intended to store equipment at the property next to its headquarters and testified that DTE could have found cheaper alternatives to store equipment.[226]

Ms. Uzenski did not address this testimony in her rebuttal presentation and DTE does not address it in its briefs. This PFD recommends that the Commission adopt the Attorney General's recommended adjustment to exclude $3.9 million from rate base because DTE has not established that it is a reasonable and prudent expenditure.

f. *Correction*

The Attorney General also recommended an adjustment to exclude additional $.8 million regarding the Grand River Public Space inadvertently included in its filing. Mr. Coppola testified that a discovery response from DTE acknowledged an oversight in including $759,000 in working capital for the Grand River Public Space.[227] DTE in its reply brief adopted this correction.[228] Based on DTE's acquiescence, this PFD considers this matter resolved.

8. <u>AMI (line 10 of Exhibit A-9, Schedule B6)</u>

Mr. Sitkauskas testified on this topic for DTE discussing DTE's updated cost/benefit analysis in Exhibit A-18 and discussing DTE's progress to date.[229] He presented Schedule B6.6 of Exhibit A-9 to provide additional information regarding DTE's recent historical and projected expenditures. He testified that DTE had

[226] See 6 Tr 1835-1836.
[227] See 6 Tr 185.
[228] See DTE reply brief, pages 2, 58.
[229] See 4 Tr 1025.

completed 77% of the planned installations by the end of 2015 and would finish the installations in 2017.[230] Mr. Matthews testified that Staff finds the projected expenses to be generally reasonable and prudent.[231] He emphasized, however, that Staff wants to be sure the technology is used to achieve benefits for ratepayers:

> Additionally, Staff believes it is important for the Company to provide accountability for their AMI/smart grid investments as identified by the Company's benefit projections. Therefore Staff recommends that the Company provide annual smart grid reporting metrics in order to provide assurance to the Commission that the increasing spending by the Company is accompanied by commensurate associated benefits of the technology chosen.[232]

No other party expressly addressed projected capital spending as an element of rate base so this PFD recommends that the projections be accepted. The reporting requirements are discussed further below.

9. <u>Renewable Energy (line 11 of Exhibit A-9, Schedule B6)</u>

DTE's filing proposed to include approximately $13 million in capital spending on renewable energy, largely in the first seven months of 2017 as shown in line 11 of Schedule B6 and line 2 of Schedule B6.12. Ms. Dimitry presented direct testimony in support of the company's capital expense projection.[233] Staff and the Attorney General recommended excluding the proposed expenditures. Staff witness Mr. Krause testified to Staff's recommendation that the renewable energy expenses be removed from this case and addressed in the Act 295 proceeding he expected DTE to initiate.[234]

---

[230] See 4 Tr 1026.
[231] See 5 Tr 1495.
[232] See 5 Tr 1495.
[233] See 3 Tr 211-214.
[234] See 5 Tr 1487-1489.

Ms. Dimitry also presented rebuttal testimony, characterizing Staff's recommendation as premature.[235]

In its initial brief, DTE cited Ms. Dimitry's testimony and argued in opposition to Staff's adjustment. In its reply brief, however, citing the Commission's September 23, 2016 order in Case No. U-18111, DTE indicates that the Commission has approved its request to amend its renewable energy plan and acknowledges that continuing to seek recovery in this rate case would be duplicative.[236] Since DTE has withdrawn its request to recover this item, this PFD considers this matter resolved accordingly and the revenue requirements calculation should reflect exclusion of the projected expenditures.

10. <u>Demand Side Management</u> <u>(line 12 of Exhibit A-9, Schedule B6)</u>

Under the heading "demand side management" on Schedule B6 of Exhibit A-9, DTE projected capital expenses totaling approximately $33.1 million. Ms. Dimitry testified in support of this expense projection and provided a breakdown showing the following cost categories in her Schedule B6.12: distributed generation; interruptible air conditioning (IAC); DTE Energy Insight; and programmable communicating thermostats (PCT). Three of these categories were the subject of dispute and are addressed in subsections a through c below.

a. *Distributed Generation*

Ms. Dimitry testified in support of a "Distributed Customer Generation" program, explaining:

> DTE Electric is exploring a Distributed Customer Generation (DCG) program. A DCG program would develop customer-owned back-up generation as a capacity resource in accordance with the EPA's

[235] See 3 Tr 241-242.
[236] See DTE reply brief, page 88.

> Reciprocating Internal Combustion Engine (RICE) National Emission Standard for Hazardous Air Pollutants (NESHAP) rules.[237]

She further testified that DTE established a pilot DCG program in 2015, and plans to continue the pilot program effort throughout the test year. The Attorney General and Staff each recommend excluding the projected $2.5 million expenditures for this program.

Ms. Trachsel testified that although Staff is generally supportive of the company's efforts, Staff recommends excluding the projected $2.5 million in proposed expenditures for the DCG program for several reasons. She testified that DTE requested and received funds for a pilot for this same program in Case No. U-17767 and indicated that DTE had no results from that program. She cited information from DTE explaining that the targeted site was no longer a feasible option.[238] She testified that Staff is not convinced that the program will be started before the end of the projected test year. Further, she testified that Staff believes any future funding request from DTE should be conditioned on it providing the results from a pilot program, documentation of the need for additional funding, and a well-developed plan.[239]

Mr. Coppola cited a DTE discovery response in his Exhibit AG-19 indicating certain EPA litigation has created uncertainty with the program. On that basis, he concluded that "inclusion of the capital expenditures in rate base [is] problematic."[240]

Ms. Dimitry did not present rebuttal testimony on this issue. While DTE notes the projected expenditure in its briefs,[241] it does not address Staff's or the Attorney

---

[237] See 3 Tr 216.
[238] See 5 Tr 1567-1568.
[239] See 5 Tr 1568-1569.
[240] See 6 Tr 1819.
[241] See DTE brief, page 103; DTE reply brief, page 94.

General's testimony. This PFD finds, as Ms. Trachsel testified, that DTE has already received funding for the pilot program and should not be granted further funding until it provides the results of the pilot, documents the need for additional funding, and presents a well-developed plan.

b*. Programmable Communicating Thermostats*

As Ms. Dimitry explained, DTE is proposing to spend $2.8 million to supply PCTs to each of 10,000 customers each year for the next five years.[242] She testified that the purpose of the PCTs is to lower peak-hour electric consumption for residential customers:

> DTE Electric also plans to start a Programmable Communicating Thermostats (PCT) program with dynamic peak pricing based on the positive outcome from the SmartCurrents pilot study from 2010-2013. As described by Witness Uzenski, DTE Electric is seeking MPSC approval to account for the purchase of equipment to support a Programmable Communicating Thermostat program as a capital investment. Capital investment in PCTs will expand and leverage the Company's existing AMI infrastructure, and provide customer value by enabling demand management programs that can reduce power supply costs. The projected capital expenditures amount to $2.8 million through July, 31 2017 as shown in Exhibit A-9, Schedule B-6.12, line 7.

Mr. Matthews testified that Staff does not object to the test year funding for 10,000 PCTs but recommends that the program be limited to the test year expenditures until DTE shows that customers are enrolling in and utilizing the program.[243] He also explained that because a well-functioning demand response defers future capital investment in peak-serving generation plants "the utility is incentivized to not use their DR program and instead pursue that same capital investment in peak-serving generation." Further, he testified: "The current regulatory structure encourages utilities

[242] See 3 Tr 219.
[243] See 5 Tr 1502.

to invest in DR infrastructure and marketing, but not to actually use the programs once they are created."[244] He testified that Staff believes that establishing specific metrics for program inputs and outputs can mitigate the adverse incentives by allowing the company to demonstrate it is fully utilizing the technologies it is investing in. Mr. Matthews testified that Staff has not developed such metrics at this point and recommends that until appropriate metrics are developed for demand response programs, a cautious approach is warranted.

Ms. Dimitry took issue with this testimony in part, asserting in her rebuttal that DTE does have an incentive to operate a well-functioning demand response program because it can receive capacity credits from MISO:

> Witness Matthews' argument fails to recognize that the continuation of the DR programs does, in fact, provide an incentive for the Company to use the DR programs. And this incentive exists today even without the additional possibility of using metrics and goals as appropriate for each program. As Witness Matthews partially recognizes, the result from a well-functioning DR program is the reduction in customer demand, which actually avoids and/or defers the capital investment in peak-serving generation plants that the Company would have to make should those DR programs not be up and running. The Midcontinent System Operator (MISO) accounts for a reduction in demand resulting from the DR resources managed by the Company. DR resources are recognized as Load Modifying Resources in the MISO market on an annual basis.[245]

Mr. Coppola recommended that the Commission exclude 50% of the projected spending for this program.[246] He expressed a concern with DTE providing the PCTs at no charge to customers.[247] He also expressed concern that the PCTs would not prove effective at reducing energy consumption in the long term.[248] Mr. Matthews provided

[244] See 5 TR 1498-1499.
[245] See 3 Tr 244-245.
[246] See 6 Tr 1823.
[247] See 6Tr 1821-1822.
[248] See 6 Tr 1822.

rebuttal on this last point, asserting that demand-side management programs can provide benefits for many customers with minimal changes in life style. He testified that Staff does not support reducing test year funding for the programmable thermostats.[249] Mr. Jester also testified to the benefits of programmable thermostats, but expressed a concern that thermostats that are "merely programmable" would not provide the same benefits as more sophisticated technology, citing DTE's own report in Case No. U-17936. [250]

In its brief, Staff also argues that the Commission should adopt Mr. Matthews' recommendation to limit its distribution to the 10,000 thermostats proposed for the test year until it shows that customers are enrolling in and the company is utilizing the program. Staff also emphasizes its concern that DTE does not have a strong incentive to promote use of its DR programs, and wants to ensure that ratepayers fund only a well-functioning DR program.[251]

The Attorney General emphasizes Mr. Coppola's testimony regarding the problems of giving away thermostats to some customers, including a concern that the costs are borne by nonparticipating customers who do not benefit proportionally and his concern that achieving significant reductions in consumption will be difficult.[252] MEC/SC/NRDC express general support for the program consistent with Mr. Jester's testimony.[253]

---

[249] See 5 Tr 1505-1506.
[250] See 5 Tr 1614-1615.
[251] See Staff brief, page 12.
[252] See Attorney General brief, pages 43-44.
[253] See MEC/SC/NRDC brief, pages 76-77.

In its briefs, DTE relies on Ms. Dimitry's testimony in arguing that DTE has a "proper and effective incentive" to engage in demand response activities.[254] DTE also cites Mr. Matthews' rebuttal testimony in response to the Attorney General's arguments.[255]

This PFD recommends that the Commission adopt Staff's recommendation to provide funding for 10,000 PCTs for the projected test year, with the expectation that DTE will report on the success of this program before seeking funding for an expansion into future years. Staff's cautious approach appears most reasonable on this record. Mr. Matthews' testimony is persuasive that DTE has at best a mixed incentive to promote use of consumption-reducing devices and the report required before additional funding will give the Commission an opportunity to consider whether PCTs should continue to be free to participating customers or whether any other safeguards are appropriate. Requiring further review before providing additional funding will also give the Commission a timely opportunity to review the technology being used, consistent with MEC/SC/NRDC's expressed concerns. In addition to the opportunity available in future rate cases to review the program, the Commission has recently provided for further analysis of such programs in its recent order in Case No. U-17936, which requires DTE to report on its demand response programs in February of 2017.[256]

c. Energy Bridges

The other demand response program at issue is DTE's "Energy Insight" program. Ms. Dimitry testified regarding DTE's "Insight program" and the use of energy bridges in conjunction with that program:

---

[254] See DTE brief, page 104.
[255] See DTE reply brief, page 90.
[256] See November 7, 2016 order in Case No. U-17936.

> The Company also continues investing in the DTE Insight program to enhance successful demand side management options. The DTE Insight program centers on a mobile application that helps customers manage their energy use and is highly integrated with the AMI infrastructure. DTE Insight directly benefits customers by enabling them to know their daily consumption, identify usage patterns, and thus explore energy conservation options in real time. Engaging customers in actively managing energy usage creates benefits for all DTE customers. Broad deployment and usage of DTE Insight and Energy Bridge devices can reduce peak demand, thus reducing generation capacity costs or delaying the need for generation capacity additions. Furthermore, broad deployment of these tools and equipment has the potential to mitigate uncollectible expenses. As low income and budget-constrained customers gain better insight into daily usage through usage alerts and budget tracking, they can make changes in real time to keep their monthly bills affordable. The Company will be funding activities to expand both program adoption and capabilities, and to integrate with Energy Bridge devices. Energy Bridge devices collect energy consumption data by connecting wirelessly to the automated meter and storing highly granular interval data to which customers can gain access through their smart phone. The goal is to distribute approximately 50,000 Energy Bridges to customers from mid 2016 to the end of July 2017. The projected capital expenditures associated with the DTE Insight program amount to $15.8 million through July 31, 2017as shown in Exhibit A-9, Schedule B-6.12, line 6.[257]

Mr. Sitkauskas also addressed the Energy Insight application in his direct testimony, "enables customers to discover their daily consumption, identify their usage patterns, and explore opportunities to reduce their usage from their mobile devices such as smart phones."[258]

Mr. Matthews explained that in order for a customer to use the energy bridge, the customer must also use DTE's Insight mobile application.[259] He testified that Staff is recommending the $5.96 million reduction on the basis that DTE has not demonstrated there is a sufficient demand from customers who will actually utilize the technology.[260] He recommended that the Commission limit the number of energy bridges purchased

[257] See 3 Tr 217.
[258] See 4 Tr 1031.
[259] See 5 Tr 1500.
[260] See 5 Tr 1500-1501.

during the test year to 16,000, on top of the 35,000 it has already purchased, to limit the number of energy bridges DTE purchases to the number of customers using the mobile application. Mr. Matthews based this limit on a discovery response in Exhibit S-10.1, showing 51,000 customers logging into their mobile application in February, thus recommending that the energy bridge purchases be limited to 51,000. He also cited DTE's estimate in Exhibit S-10.3 that 35% of the customers who request an energy bridge never install it.

In her rebuttal testimony, Ms. Dimitry first addressed the demand from customers for energy bridges. She testified that Mr. Matthews relied on a set of data that "is not appropriate" to justify the actual number of downloads associated with the DTE Insight application. She testified that the mobile application identified in Exhibit S-10.1 is the "DTE mobile application which includes outage and payment functionality," not the DTE Insight application.[261] She presented additional information in Exhibit A-29, Schedule S1 to show that as of the end of 2015, 59,000 unique customers downloaded the DTE Insight application and another 18,937 downloaded the application in the first four months of 2016. She testified that the total number of "logins" as of the end of June 2016 is 82,000. From this she concluded: "Evidently, customers are engaged in the program." From the 82,000 customers that downloaded the application, she reasoned, in addition to the 35,000 energy bridges that DTE has already purchased, an additional 47,000 would be appropriate and "consistent with the goal of distributing 50,000 bridges by the end of the test year in July 2017 as I stated in my direct testimony."[262]

---

[261] See 3 Tr 243.
[262] See 3 Tr 243-244.

In its brief, Staff also argues that DTE should recover the cost of energy bridges from customers, at least customers who request an energy bridge and never install it.[263] Staff acknowledges Ms. Dimitry's rebuttal testimony showing a greater number of Insight application downloads[264] but points out that the company's download statistics show an average of 2 applications downloaded per household: "Ms. Dimitry's projections are incorrect, as she overlooks the fact that an energy bridge is an electronic attachment to a house's internet router and thus no home has more than one energy bridge."[265]

DTE relies on Ms. Uzenski's rebuttal testimony in its briefs.[266] In its reply brief, DTE takes issue with Staff's analysis, arguing that Ms. Uzenski's use of the phrase "unique customers" meant households.

Mr. Coppola also reviewed these proposed expenses, presenting a discovery response from DTE in his Exhibit AG-20 showing 59,080 customers downloading the mobile application and 16,377 energy bridges shipped. He also identified DTE projections of 118,000 customers downloading the application by the end of 2016, with 39,000 or 33% of those customers requesting an Energy Bridge. He testified that most of the $16,282,000 in capital expenses projected for 2016 and 2017 are for the $101-per-unit bridges. Mr. Coppola objected to DTE's plans to provide the Energy Bridges at no charge to customers, as he did with the PCTs:

> Fundamentally, there are a number of dangers and policy issues that arise from such a practice. One, non-participating customers are paying for the cost of applications and devices used by only a fraction of the customer population. Although, there may be some incidental benefits to the total

[263] See Staff brief, pages 9-12, citing 5 Tr 1502 and Exhibit S-10.3.
[264] See 3 Tr 243 and Exhibit A-29, Schedule S1.
[265] See 3 Tr 243 and Exhibit A-29, Schedule S1.
[266] See DTE brief, pages 103-104; see DTE reply brief, pages 89-90.

> customer base from energy reduction by those customers, the benefits are disproportionally accruing to those customers who received the devices for free.
>
> Two, it is not clear if the energy savings will be sustained after the initial excitement of using a new device or app wears out and customers return to their usual habits. . . .
>
> Three, giving out free devices, or free anything, lessens the value of the item in the eyes of the recipient. Since he or she did not pay for it, it is easier to abandon its use because it did not cost them anything. In fact, the Company estimates that 35% of the Energy Bridges distributed have not been installed and customers are not using them. This is a considerable waste of ratepayers' money. With no real or perceived "skin in the game", we may find in coming years that after incurring millions of dollars of expenditures there is only marginal participation and energy savings. The customer must perceive value in the device or app and must make a financial investment that he or she is convinced that will pay back that investment with continued use. It is also dangerous to give free stuff out now and expect other customers to pay for it later as the Company may be contemplating. Customers, who may want to participate in the future, would not be happy to pay for a device that other customers received for free. Such a change later would be a turn-off to increased customer participation.[267]

Mr. Coppola recommended that the Commission include only 50% of DTE's forecast expenditures in rate base for both energy bridges and PCTs, removing $9.5 million. Further, he recommended that the Commission require DTE to establish a cost for participating customers to use the DTE Insight application and the Energy Bridge.

In addition to this recommendation, Mr. Coppola raised a concern regarding DTE Energy's creation of an affiliated joint venture with the firm DTE paid to develop the Insight application and related technology.[268] He testified:

> I find this arrangement unacceptable. A non-utility affiliate of the Company is benefiting from the investment in a technology that utility customers are funding through rates. Although DTE Energy Ventures may have contributed some additional investment capital to launch the joint venture

[267] See 6Tr 1821-1823.
[268] See 6 Tr 1824-1826, Exhibit AG-22.

with Vectorform, that joint venture would not have been possible without the $13.1 million spent by the DTE Electric to develop the technology.[269]

Further, he testified:

> According to responses received from the Company to other discovery requests: "DTE Electric received a free perpetual license to use the existing app and existing platform and also the right to license new features or apps developed by the Joint Venture or to purchase hardware from the Joint Venture at the lower of cost or market." This statement is ludicrous. This is the least that DTEE should have received. As the party who funded the development of the technology, DTEE should also have received and retained rights to commercialize the technology and offshoots of that technology to third parties. This would then allow the Company the opportunity to offset at least some, or perhaps all, of the investment and cost to develop the Energy Insight and related technology.
>
> Instead, DTE Energy Ventures has leveraged the investment that will be paid by the Company's utility customers in order to benefit shareholders. In response to a discovery request, the Company provided the analysis it performed to justify its investment in the Joint Venture. The analysis shows that for the period from 2015 to 2024, the Joint Venture may realize revenues of $203 million. DTE Energy Ventures has also estimated that, based on typical technology company valuation multiples, the Joint Venture could be worth in a range of $100 to 300 million in less than 5 years. This is value that should accrue mostly to utility customers. Exhibit AG-23 includes the Joint Venture valuation analysis.[270]

Mr. Coppola recommended that the Commission require DTE to transfer any value generated by the joint venture to DTE at a percentage proportional to its investment.[271]

Ms. Dimitry did not specifically address Mr. Coppola's testimony on these topics.

In its reply brief, DTE argues:

> Furthermore, the AG's suggestion that the commercial arrangements involved with the DTE Insight application justify transfer of some value from DTE Energy to DTE Electric is unjustified and without merit. (AG Initial Brief pp 44-45) As the Company explained in Exhibit AG-22, DTE Electric is a licensee of the relevant technology at no cost. The holder of the intellectual property rights created a joint venture to commercialize additional products of the third party platform and DTE Energy's

[269] See 6 Tr 1824.
[270] See 6 Tr 1825.
[271] See 6 Tr 1826.

> ownership interest in the joint venture was funded with non-regulated funds.[272]

Recognizing that the projected expenditures are relatively small, this PFD recommends that the Commission adopt Staff's analysis. Both the Attorney General and Staff are rightly concerned that DTE would just send out energy bridges to customers, only to have them end up unused. Even if DTE is correct that Ms. Uzenski's unique customer identification tracks households rather than individuals in a household, there is no dispute that some energy bridges have ended up unused, as shown in Exhibit S-10.3. While Staff appears to be working with the company on a "recovery" program, see Exhibit S-10.4, the Commission should require an evaluation of the energy bridge program in the company's next rate case before any additional funding is provided. DTE should also provide an analysis of the results of its experiments as outlined in Exhibit S-10.4, including an analysis of whether paying customers to install the bridge actually promotes use of the devices. Also, as discussed above, the Commission has an ongoing inquiry into DTE's demand response programs, with additional reporting and analysis expected by February1, 2017.[273]

This PFD also finds Mr. Coppola's testimony persuasive that the Commission should be concerned with DTE's joint venture. DTE did not provide testimony addressing Mr. Coppola's concern. In its discovery response, Exhibit AG-22, DTE indicates it expects to purchase future software upgrades from this joint venture and also refers to "hardware" with no greater specificity. DTE did not provide sufficient information on this record for the Commission to determine whether the company has essentially locked in ratepayers to paying for software (and potentially other unspecified

[272] See DTE reply brief, page 91.
[273] See November 7, 2016 order in Case No. U-17936.

"hardware") from a DTE affiliate in order to have access to the AMI meter data. In the absence of such additional information, Mr. Coppola's recommendation regarding the ratemaking treatment for an affiliated transaction appears premature. Instead, the Commission should make clear to DTE that it should have no expectation of receiving ratepayer funding for any payments to the joint venture without an additional showing that it did not breach any duty to the ratepayers or violate the code of conduct. Recognizing that the Commission's November 7, 2016 order in Case No. U-17936 requires DTE to report on its demand response programs, the Commission should expect DTE's report in that docket to include information regarding planned affiliate transactions related to DTE's demand response programs, so that the Commission can fully evaluate the utility's incentives regarding these programs.

B. Working Capital

The Commission has explained working capital as follows:

> For ratemaking purposes, working capital is a measure of investor funding of daily operating expenditures and a variety of non-plant investments that are necessary to sustain ongoing operations of the utility. The ratemaking measure of working capital is designed to identify these ongoing funding requirements on average over a test period. Working capital requirement is determined by "an analysis of all the assets of the utility to determine which are used to provide service and an analysis of all of the utility liabilities to determine the extent to which assets are funded by capital that is tied to the earnings of the utility."[274]

DTE's revenue requirement calculation as originally filed was based on a projected test year average working capital balance of $1.3 billion. In its initial brief, DTE revised its working capital balance to reflect two adjustments: removing a portion of the requested regulatory asset for tree trimming expenses attributable to 2014 and 2015, and

[274] See October 20, 2011 order in Case No. U-16472, page 26, citing June 11, 1985 order in Case No. U- 7350, page 4.

reclassification of obsolete inventory as depreciation. The disputed issues that impact the calculation of working capital are the treatment of DTE's Combined Operating License (COL) expense for a potential Fermi 3, DTEE's request to recover certain non-qualified benefit costs, and the treatment of its projected negative Other Post-Employment Benefit (OPEB) expense. These are addressed below, along with the adjustments that are no longer disputed.

1. <u>Detroit Investment Fund</u>

Staff and the AG both recommended removal of DTE's investment in the Detroit Investment Fund from DTE's projected working capital balance. Mr. Coppola characterized it as a non-utility investment and recommended a $4.9 million adjustment.[275] Based on its audit, Staff recommended a $3.3 million adjustment to exclude a non-utility item, and Mr. Gerken explained the basis for removing it from working capital in his testimony:

> Staff's audit of the Company's Exhibit A-9, Schedule B4, revealed that line 3 included $3,288,427 for DTE Electric's equity interest in an investment by the name of the Detroit Investment Fund. As supported by Staff's Exhibit S-12.1, DTE Electric acknowledges the investment is a non-utility item which is included in its working capital requirement. Further, DTE Electric acknowledges the purpose of the investment fund is to provide a source of private sector financing designed to be a catalyst for investment in the City of Detroit by financing commercial projects and entities to stimulate economic development and job creation.[276]

He also testified that Consumers Energy has an investment in this fund but does not include it in rate base, and presented supporting materials in his Exhibit S-12, Schedule S-12.2.[277] Staff addressed this issue in its brief at page 24, noting that DTE did not provide rebuttal testimony on this issue. DTE also did not address this issue in its

[275] See Coppola, 6 Tr 1841.
[276] See 5 Tr 1478-1479.
[277] See 5 Tr 1479-1480.

briefs. On the basis that Staff's adjustment was unrefuted on this record, this PFD recommends that the Commission adopt the adjustment.

2. Closed Plant Obsolete Inventory

In its rate case filing, DTE included in working capital a regulatory asset for obsolete inventory as a result of plant closures with a five-year amortization.[278] Mr. Nichols explained that DTE had sought accounting approval for the regulatory asset in Case No. U-18033 or as an alternate authority to treat the obsolete inventory as a cost of removal. He testified that the Commission's May 20, 2016 order in that docket approved the alternate authority and Staff adjusted working capital accordingly.[279]

In its initial brief, DTE now appears to agree that Staff's treatment of obsolete inventory in this case is correct. DTE's acknowledgement resolves this issue, which affects the working capital, the accumulated provision for depreciation, and the depreciation and amortization expense elements of the rate calculations.[280]

3. Fermi 3 (COL)

In Case No. U-17767, DTE requested recovery of the costs of obtaining a Combined Operating License (COL) to potentially construct the Fermi 3 nuclear plant. In its January 19, 2015 order on rehearing, the Commission determined that DTE would be allowed to amortize and recover the COL expenses before making a decision on whether to build the plant, but would not be allowed to recover a return on those expenses from present ratepayers:

> The utility will be made whole for the cost of seeking the license, but ratepayers will not be expected to continue to provide a return on an asset whose real value is undefined at this point. DTE Electric was cautioned in

[278] See Uzenski, 4 Tr 816.
[279] See Nichols, 5 Tr 1524.
[280] See DTE brief, page 10, 16, 40.

> the October 20, 2011 order in Case No. U-16472, p. 72, (its last rate case) that it should not continue to 'project costs and make expenditures in large amounts without making progress toward construction or deciding to construct a new plant.' If the utility chooses to build the unit in the future, it may seek a return on its assets at that time; and, if it indeed builds a nuclear unit, the return is likely to be substantial. In the meantime, when the value of the license is undefined and the facility is not providing service to customers, ratepayers will not be required to provide a return on this asset. Based on the record, the license is a transferrable asset with some value, and the Commission did not intend in the December 11 order to cut off consideration of further ratemaking treatment if the license is sold.[281]

In its rate application in this case, DTE asks that the Commission allow DTE to recover not only the licensing costs as provided for in that order, but also a return on those costs by allowing DTE to include the unamortized balance of the COL expenses as a regulatory asset in working capital. Ms. Dimitry testified for DTE on this topic:

> The Company made reasonable and prudent expenditures to create an asset that has tangible value. DTE Electric is maintaining the COL at the Fermi site in current status as a useful and valuable asset for its customers with a relatively low price. There are multiple facts and records that confirmed the Company's prudency and reasonableness in obtaining and holding the COL. The Commission has consistently indicated that the original Company decision to seek the license was a reasonable one. The Commission has also found that, based on records from prior rate case proceedings, the incurred costs to obtain and maintain the COL were reasonable. In addition, the Commission acknowledged in its recent Order on Rehearing in Case U-17767 that the license is a transferable asset that is valuable. The value of this asset is demonstrated in a number of ways. To DTE Electric's knowledge (and nobody has demonstrated otherwise through multiple rate proceedings) the Company has obtained the Fermi 3 COL more economically than any other applicant for a COL. The license can be maintained indefinitely because it has no expiration for the start and completion of plant construction. It is the only active nuclear license in the Midwest region, and could provide greater than 1,500 MW of carbon-free generation which has value in the face of changing environmental and energy regulation. This makes the COL a marketable asset, opening the possibility of other ownership, partnership and selling options if the Company decided not to build the plant.

[281] See January 19, 2015 order, Case No. U-17767, pages 6 and 7, also quoted in Mr. Welke's testimony at 6 Tr 1579-1580.

> Thus, the Company contends that the Fermi 3 COL is an asset in itself, has a defined value at this point, and is transferable. A potential buyer or partner would reasonably expect to pay for not only the total direct expenditures incurred in obtaining and holding the license, but also the value associated with financing these expenditures during the long seven year licensing process.
>
> DTE Electric believes that the requested "Return On" these COL expenditures represents fair and reasonable compensation to debtholders and shareholders that, through the Company, have invested in the creation of this reasonable, prudent, and valuable COL asset. Utility investors, whether debtholders or shareholders, have expectations to earn a fair return on those investments which have been determined to be reasonable and prudent by regulators, and which provide value to utility customers. These return on expectations are rational and are based on the fact that their investment funds could have been deployed elsewhere to earn investment returns. It is the expectation of investment returns which make utility capital markets work. Denying a return on the COL investment would harm DTE's investors in the form of lost opportunity costs. It would be a bad precedent to deny return on an asset that has been deemed reasonable and prudent and which has value to utility customers. Such a precedent can create uncertainty in utility capital markets, which can impact liquidity, the availability of funds for necessary infrastructure investments, and increase utility financing costs which are born by utility customers.[282]

Ms. Dimitry testified that DTE has incurred $92.9 million to obtain the COL, and referenced Exhibit A-9, Schedule B.6.7, page 2, line 2, for the balance of expenditures.[283] She testified that DTE has also "been incurring" costs to develop the Holder Program to retain the COL at the Fermi site, which are projected to be $5.6 million through July 31, 2017, and "relatively small additional costs until a decision regarding plant construction or license transfer can be made," projected to be $1.8 million through July 31, 2017, as shown in Schedule B.6.7, page 2, line 4.[284] She testified:

[282] See 3 Tr 228-229.
[283] See 3 Tr 223.
[284] See 3 Tr 224-225.

> The updated forecast of expenditures projected through July 31, 2017, the end of the test year in this proceeding, amounts to $100.3 million. The represents a slightly lower amount than the $101.9 million amount that was projected, requested and determined to be reasonable in Case No. U-17767.[285]

Staff, the Attorney General, ABATE, and MEC/SC/NRDC recommend that the Commission exclude this entire amount from working capital and thus from rate base.[286] The parties each cite the Commission's January 19, 2015 order in DTE's last rate case, quoted above. Mr. Welke testified that the Commission did not preclude the opportunity for DTE to earn a return on the COL expense deferrals but deferred a ruling on the recovery until such time as the utility makes a build or no-build decision concerning Fermi 3. Based on his review of the Commission's orders in DTE's last rate case, the Commission already considered the arguments presented by Ms. Dimitry in her direct testimony and rejected those arguments.[287] Staff therefore recommended that the Commission continue this treatment.

In his testimony, Mr. Jester presented as Exhibit MEC-7 a discovery response from Ms. Dimitry, acknowledging that the company has no new evidence or circumstances in support of its request.[288] Mr. Jester also testified that while DTE's testimony in this case indicates it is undecided whether to build the nuclear plant, DTE has otherwise indicated that it does not intend to build the plant. As evidence that DTE has decided not to build a nuclear plant, he cited Exhibit MEC-8 (a long-range generation resource plan prepared by DTE), Exhibit MEC-9 (stating that the last long-range generation resource plan DTE prepared that did include Fermi 3 was prepared in

[285] See 3 Tr 225.
[286] See Welke, 6 Tr 1578-1581; Coppola, 6 Tr 1828-1830; Jester, 5 Tr 1634-1639.
[287] See 6 Tr 1581.
[288] See 5 Tr 1636.

2013), and DTE's Exhibit A-6, Schedule F1 in this case.[289] He also testified that DTE is pursuing plans to build natural-gas-fired plants instead, and presented analyses from DTE in his Exhibits MEC-10 and MEC-11 showing that the natural gas and carbon prices required to justify Fermi 3 are significantly higher than current prices and higher than Mr. Jester believes likely. He also testified that DTE could seek to recover its costs through a Certificate of Necessity proceeding under 2008 PA 286, MCL 460.6s.

Mr. Coppola likewise concluded that DTE had presented no new evidence; he also recommended a longer amortization period in the event the Commission decided to reconsider its earlier decision:

> [I]f the Commission wishes to revisit its decision of January 19, 2016, I recommend that the amortization of the deferred amount be calculated over 40 years. This is the minimum operating life of the COL from completion of construction of the plant, as approve by the Nuclear Regulatory Commission. This is more generous to the Company then what is typically acceptable. Under the accounting matching principle, such costs should be amortized over the plant's useful life which is the 40-year operating period following completion of construction. Therefore, those costs should not be amortized until the plant begins operation and generates revenue. Similarly, no return on the deferred balance should be granted until the plant is up and running.
>
> It is not fair or reasonable to have current customers pay for costs that are not related to productive generating assets or assets that are not creating value currently. In her direct testimony and responses to discovery, Ms. Dimitry argues that the COL has significant value to the Company and prospective developers of nuclear plants, yet all the current economic analysis that the Company has presented shows that building such a plant would not be economical at this point in time and is not likely to be economical for many years to come given all the other lower cost generation options available to the Company and to other electric utilities around the country.[290]

Mr. Dauphinais also testified on this topic, indicating that ABATE agrees with the Commission's ruling in Case No. U-17767 and recommending that the Commission

[289] See 5 Tr 1637.
[290] See 6 Tr 1829.

reject DTE's request to earn a return on the COL expenses because the ratepayers receive no current benefit from the license, "which is not used and useful in providing service."[291]

In her rebuttal testimony, Ms. Dimtry reiterated the reasons she provided in her initial testimony and disputed that DTE would be able to recoup a deferred return:

> If the Commission approved a return on the Company's COL investment at a future point in time when the Company decided to build the plant, the Commission's decision would actually deny return on the balance of expenditures from today to that future moment. In the January 19, 2016 Order in Case No. U-17767, the Commission authorized the return of the COL expenditures through amortization over 20 years. As the balance of COL expenditures decreases each year due to amortization, the potential authorized return on investment at a future time would be calculated on a reduced amount. This results in, not a deferral, but a permanent loss of return on the Company's investment for that time period unless this situation is corrected through a ruling in this case to authorize a return on the Company's reasonable and prudent investment in its valuable COL. Exhibit A-29, Schedule S2 provides a detailed calculation of a loss of return on COL expenditures under three cases in which the Company would decide whether to build the nuclear plant (lines 11 to 23), and amply demonstrates that denial of a return on the Company's COL investment in this case denies the Company a fair return on a reasonable and prudent investment.[292]

In its briefs, DTE reviews the history of Commission orders addressing its COL costs, citing the Commission's December 23, 2008 order in Case No. U-15244 and its October 20, 2011 order in Case No. U-16472. Regarding Case No. U-16472, DTE argues:

> [T]he Commission approved the majority of COLA expenditures, and ordered that $6.7 million should be deferred for future review. Accordingly, DTE Electric put a regulatory asset in place for COLA costs, and requested a 20-year amortization period in its last general rate case.[293]

[291] See 6 Tr 2009.
[292] See 3 Tr 248.
[293] See DTE brief, page 98.

DTE maintains that the record reflects it is prudent and reasonable for DTE Electric to obtain and possess the COL without presently deciding exactly what to do with it. Also, DTE argues that it "takes out significant risks from nuclear construction work, greatly shortens the time horizon to have a nuclear plan in service . . . and provides DTE Electric with tremendous flexibility to serve Michigan customers under rapidly changing environmental, regulatory, and economic conditions."[294] DTE emphasizes its view that the license itself is a marketable asset "offering a number of possible ownership, partnering, and sales options."[295]

In its brief, Staff expressly addresses three arguments DTE presented to persuade the Commission to revise its recent decision: that it made reasonable and prudent expenditures to obtain the license; that the license is a valuable asset to customers since it provides flexibility in the face of changing regulations; and that shareholders should receive fair compensation. Staff argues that the Commission rejected all of these arguments in its order in Case No. U-17767.[296] Staff argues that the entire $96.9 million in past expenditures should be excluded from working capital as shown in Exhibit S-2, Schedule B4, line 28.

MEC/SC/NRDC review Mr. Jester's testimony taking issue with DTE's claim that it has not yet decided whether to build the nuclear plant. They also cite DTE's pending PSCR plan case, Case No. U-17920, indicating that DTE has asked the Commission to approve cost recovery for a 20-year contract for firm natural gas transport capacity on the NEXUS pipeline and plans to submit an application for a Certificate of Necessity for new gas plant(s) as early as 2017. MEC/SC/NRDC also argue that DTE has not

[294] See DTE brief, page 99.
[295] See DTE brief, page 100.
[296] See Staff brief, pages 25-26.

attempted to establish a “market value” for the COL, and that the value of the license is limited by its geographic restriction.[297] They argue that in its January 19, 2016 order on rehearing in Case No. U-17767, the Commission acknowledged that until the facility is built, it is not providing service to customers, and thus for ratepayers, “the real value is undefined at this point.”[298] They also cite the Commission’s Oct. 20, 2011 decision in Case No. U-16472 in arguing that investors could not have formed a reasonable expectation of recovering a return on the COL in advance of construction. Addressing Ms. Dimitry’s rebuttal argument that DTE will not be able to recover a return on amounts already amortized, they argue:

> Witness Dimitry notes in rebuttal that the company will never obtain a return on the portion of its investment that has already been amortized. However, the company elected to seek a premature return of its investment in the prior rate case . . . rather than treating the investment as a deferred credit until the CON process, as the Commission ordered in 2011. Thus, it was the company’s decision to amortize and include part of its COL costs in its rate base, rather than deferring the entire remaining expense, as ordered by the Commission in 2011 and as permitted by 2008 PA 286 (MCL 460.62). The situation described by Witness Dimitry, whereby the balance on the COL investment decreases each year due to the amortization of the investment, was created by the company.[299]

MEC/SC/NRDC also note that DTE has continued to invest in the plant notwithstanding the Commission’s orders in Case Nos. U-16472 and U-17767. They argue that the Commission should decline to include DTE’s post-COL expenses related to Fermi 3 in rate base:

> And yet, since the company obtained the COL in 2015, the company has invested another $7.4 million related to the COL. But the company’s long-term planning does not – and has not since 2013 – included Fermi 3. The Commission should defer all post-COL activities until the company decides to build and pursue the plant. Alternatively, the Commission

[297] See MEC brief, page 15, citing 3 Tr 261-264, and Exhibit MEC-39.
[298] See MEC/SC/NRDC brief, page 17, citing January 19, 2016 order in Case No. U-17767, page 6.
[299] See MEC/SC/NRDC brief, page 18 (citations omitted).

> should exclude plant design expenditures ($1.8 million) from the company's rate base.[300]

The Attorney General and ABATE also argue that the Commission should not provide a return on the licensing expenditures. The Attorney General argues that there is no basis to permit DTE to relitigate this issue, noting that Mr. Coppola also recommended a longer amortization period if the Commission does decide to reconsider its January 2016 decision.[301] ABATE also cites the Commission's decision in Case No. U-17767, as well as Mr. Dauphinais's testimony.[302]

DTE's reply brief is essentially a repetition of its initial brief. It does not address Mr. Jester's testimony directly or the specific arguments made by the parties in their briefs.

This PFD finds that the Commission's prior orders on this issue have already specified the ratemaking treatment of these expenses, and the recommendations of Staff, the Attorney General, ABATE, and MEC/NRDC/SC to exclude COL expenses from working capital should be adopted. As these parties argue, DTE has not provided any new evidence or changed circumstances to support revisiting the Commission's January 2016 order in Case No. U-17767.

DTE attempts to argue that this issue has not already been resolved by the Commission's order in Case No. U-17767 by claiming:

> DTE Electric's requires for a return on, as well as of, its investment in providing utility service is in accordance with fundamental ratemaking law. Utility investors are entitled to earn a fair return on investments that, as here, are reasonable and prudent, and provide value to utility customers. Moreover, as a matter of regulatory policy, the Commission should not

[300] See MEC/SC/NRDC brief, page 21.
[301] See Attorney General brief, pages 47-48.
[302] See ABATE brief, page 40.

> continue to deny return on an asset that it has already found to be reasonable and valuable. . .
>
> Finally, just like "justice delayed is justice denied," the continued delay of a return on the COL investment constitutes a denial of that return. As the balance of COL expenditures decrease each year due to amortization, the potential authorized return on investment at a future time would be calculated on a reduced amount. Unless corrected, this will result in not merely a deferral, but a permanent loss of return on the Company's investment for that time period."[303]

But, as DTE also acknowledges in its brief, it is asking for non-traditional ratemaking treatment for this expense item, urging the Commission to ignore the traditional "used and useful" test to permit the item to be included in rate base in anticipation of a future need.[304] Although DTE argues that the license is an "asset" that is "valuable", it is not an asset used in provided utility service to current customers. Nor has DTE established the value of the asset, as the Commission found in Case No. U-17767. DTE customers are not required to pay for assets that might be useful sometime and might increase in value.

A remaining question then is the extent to which DTE can recover for additional COL-related capital expenditures not included in the amortization provided for in the Commission's order in Case No. U-17767. The amortization expense reflected in DTE's revenue requirement is the amortization of the $98.5 million total expenditure DTE expects to have spent by the beginning of the projected test year.[305] The costs DTE projects to incur during the test year are included because DTE proposed a vintage–year accounting system in which costs would begin to be recovered the year following the year they were incurred. As Ms. Uzenski explained, this amount is less

[303] See DTE brief, pages 100-101, citing 3 Tr 228-229, 247, and Exhibit A-29, Schedule 2.
[304] See DTE brief, page 99 and n70, citing *General Motors v Public Service Comm*, 175 Mich App 576 (1989); and *ABATE v PSC*, 208 Mich App 248, 258-259 (1994).
[305] See Exhibit A-9, Schedule B6.11.

than the full amount the Commission authorized in Case No. U-17767. While DTE candidly acknowledged that it did not spend the full amount the Commission found it had spent in Case No. U-17767, the Commission's order in that case is clear that DTE is authorized to amortize $101.9 million over 20 years.[306] Beyond that amount, the utility may continue to defer its expense and seek recovery at a later date if it decides to build the plant or sell the license, as Mr. Welke testified. In approving amortization of the company's projected amount of $101.9 million in Case No. U-17767, the Commission indicated that DTE should not be incurring much in the way of additional costs, making its decision on this issue final until DTE's decision on building the plant. The Commission stated:

> If the utility chooses to build the unit in the future, it may seek a return on its assets at that time; and, if it indeed builds a nuclear unit, the return is likely to be substantial. In the meantime, when the value of the license is undefined and the facility is not providing service to customers, ratepayers will not be required to provide a return on this asset. Based on the record, the license is a transferrable asset with some value, and the Commission did not intend in the December 11 order to cut off consideration of further ratemaking treatment if the license is sold.[307]

From a review of the Commission's orders, this PFD concludes that the Commission did not intend to revisit additional small expenditures related to the license in the absence of a decision by the utility to build or not build.

4. Regulatory Asset for Tree Trimming.

In its rate case filing, DTE requested that the Commission approve regulatory asset treatment for the Enhanced Vegetation Management Program (EVMP) expenses DTE incurred in 2014 and 2015 and for the projected 2017 expenses for the renamed Enhanced Tree Trimming Program (ETTP). Mr. Whitman testified that DTE changed

[306] See January 19, 2016 order, page 5.
[307] See January 19, 2016 order, pages 6-7.

the name of the Enhanced Vegetation Management Program discussed in Case No. U-17767 to the Enhanced Tree Trimming Program to reflect customer preferences for this new name.[308] In her direct testimony, Ms. Uzenski testified that she directed Mr. Whitman to include an amortization of the 2014/2015 EVMP/ETTP expenses in his cost presentation, characterizing the 15-year amortization period used as "consistent with the amortization period of other long-term regulatory assets.[309]

Staff and the Attorney General recommended that the Commission reject DTE's request for regulatory asset treatment for the EVMP/ETTP expenses. Mr. Mazuchowski testified to Staff's view that DTE has not presented any new evidence to justify a different result than the Commission reached in Case No. U-17767.[310] Mr. Welke testified:

> Michigan's Uniform System of Accounts, Electric Plant Account Instruction No. 9, Equipment, states that capitalization of forestry expenses are appropriate for "those costs incurred in connection with the first clearing and grading of land and the right of way." EVMP is an expansion of the first clearing. (See Case No. U-17767, 5 TR 1031). Further, the EVMP expenses totaling $39,811,000 in this case are the same expenses the Commission denied capitalization for in Case No. U-17767. That order relied on Staff rationale for denial of capitalization. Lastly, regulatory asset treatment is a distinction with very little difference from capitalization. Therefore, Staff does not support the Company's proposed regulatory asset treatment of EVMP expenses in this case.[311]

Mr. Coppola similarly testified that the Commission has previously determined that these expenses should not be capitalized, and to be consistent with that determination,

[308] See 3 Tr 294.
[309] See 4 Tr 814.
[310] See 5 Tr 1516.
[311] See 5 Tr 1583.

no regulatory asset should be created.[312] He characterized the portion of DTE's request related to the 2014 and 2015 EVMP expenses as retroactive ratemaking.

Ms. Uzenski's rebuttal testimony acknowledged that the historical balance of $26.3 million is not recoverable as a regulatory asset based on the Commission's rehearing order in Case No. U-17767.[313] She explained that the historical balance of $26.3 million should be removed from working capital but testified that DTE continues to seek regulatory asset treatment for $13.5 million in projected ETTP costs for 2017. Ms. Uzenski disputed that regulatory asset treatment is the same as the capitalization rejected by the Commission in Case No. U-17767, arguing that the Commission has broad discretion to create a regulatory asset for an expense by deciding to provide for recovery over future periods:

> The Uniform System of Accounts defines Regulatory Assets as assets that: "result from rate actions of regulatory agencies. Regulatory assets and liabilities arise from specific revenue, expenses, gains, or losses that would have been included in net income determination in one period under the general requirements of the Uniform System of Accounts but for it being probable that such items will be included in a different period(s) for purposes of developing rates that the utility is authorized to charge for its utility services." A regulatory asset is essentially a deferral of costs that would normally be expensed as incurred. Such deferral generally occurs when the Commission provides for recovery over future periods. If the Commission approves regulatory asset treatment and the inclusion of the related amortization expense in future rates, the EVMP costs that would otherwise be expensed as incurred can be deferred.[314]

Consistent with Ms. Uzenski's testimony, in its initial brief DTE has revised its revenue requirements calculation to exclude $26,348,000 of the proposed regulatory asset from working capital and the corresponding $893,000 amortization of that amount

[312] See 6 Tr 1810-1812.
[313] See 4 Tr 865.
[314] See 4 Tr 866.

from the depreciation expense component of net operating income.[315] DTE also notes that its agreement to withdraw this amount is limited to this case and not intended to prejudice the company's pending appeal of the Commission's decision in Case No. U-17767. DTE argues that projected 2017 spending of $13,463,000 should be recognized as a regulatory asset with a 15-year amortization period.[316]

Mr. Whitman testified that DTE plans to trim approximately 4,150 line miles in 2016 at a funding level of $59.8 million and an average cost of $14,397 per mile. He testified that this is equivalent to a seven-year cycle, presenting as Schedule M3 of Exhibit A-21 a diagram to illustrate how the length of the cycle increases the scope of the required work. He testified that the company's work would be more extensive in Zones 1 and 2, and he testified that the company uses a four-phase process to implement the program including Initiation, Planning, Execution, and Closing phases.[317]

Mr. Whitman testified: "Relative to a five year cycle, this additional increase in the cycle length is expected to increase system SAIFI (System Average Interruption Frequency Index) by between 0.30 and 0.36, and total annual reactive costs by between $40 million and $48 million."[318] He presented charts showing DTE's plans to ramp up to a five-year cycle by 2019, and expected costs through 2021.[319] He also presented a charge showing that of the 4,150 miles DTE plans to clear in 2016, 1,391 miles are subtransmission lines that have traditionally been trimmed on a three-year schedule using standards that are similar to the enhanced specification with a relatively

[315] See DTE brief, page 59.
[316] See DTE brief, pages 52-60.
[317] See Tr 294-302.
[318] See 3 Tr 302.
[319] See 3 Tr 303-304.

low cost per mile. Similarly, of the 5,175 miles DTE plans to clear in 2017, 1,764 miles are subtransmission lines.

Mr. Whitman reviewed the benefits DTE estimated in Case No. U-17767 from its proposal in that case. He testified that DTE continues to expect a 40% reduction in SAIDI, but over a 13-year period rather than a 10-year period due to trimming fewer miles per year.[320] He also testified that the costs customers bear due to frequent outages will be reduced proportionally to the improvement in service reliability.[321] Citing a 2015 study funded by the U.S. Department of Energy (DOE) and conducted by the Ernest Orlando Lawrence Berkeley National Laboratory, he testified that DTE has estimated the value to customers of improved service reliability, also citing Mr. Wuepper's testimony. He estimated a savings of $39.4 million to be realized by customers in 2017, a "net financial benefit" to customers starting in 2018, and cumulative savings of $729.9 million by 2026.[322] He also testified to the experiences with one particular circuit in Howell where 1 mile was trimmed to the company's enhanced specification in 2011. He presented pictures in Schedule M4 of his Exhibit A-21, and testified that this one-mile section of the circuit has experienced a 75% reduction in tree-coded interruptions during the five years after trimming in comparison to the previous five years.[323] Mr. Whitman also described the company's plans for a pilot program in accordance with the Commission's order in Case No. U-17767. He identified the following key elements: 1. Selection of specific circuits to comprise the pilot program. 2. Enhanced trimming and tree removal on selected circuits, including

[320] See 3 Tr 306.
[321] See 3 Tr 307.
[322] See 3 Tr 308-312.
[323] See 3 Tr 313 ("This was done in response to a specific reliability issue regarding frequent outages and downed wires on their property.")

removal of hazard trees. 3. More in-depth root cause analysis of outages on circuits within the scope of the pilot program.[324]

Citing Mr. Whitman's testimony, DTE emphasizes that it is abandoning any use of a "clearance circle" around conductors and planning to use exclusively the Enhanced Tree Trimming Program (ETTP).[325] DTE argues that it has modified the program to address the Commission's decision in Case No. U-17767 and its experiences in the first two years of the program. DTE views the ETTP as focused on dramatically improving the overall reliability of electric service with benefits to customers from reduced outage costs, a shift from proactive to reactive maintenance activities, reduced tree-trimming costs, and increased customer satisfaction from improved power quality reliability.

DTE disputes Staff's and the Attorney General's contention that there is little difference between the company's request for regulatory asset treatment of these expenses and the capitalization the Commission rejected in Case No. U-17767. Citing and closely tracking Ms. Uzenski's rebuttal testimony at 4 Tr 865-866 DTE argues:

> Staff's reasoning is unsound because the Uniform System of Accounts ("USoA") provides specific criteria to be met for expenditures to be capitalized as Property, Plant and Equipment ("PP&E"). The Commission concluded that ETTP costs did not meet the definition of "first clearing," which is one criterion for capitalization treatment of these costs. Regulatory assets are not included in PP&E, however, and the USoA's definition of "regulatory assets" is very different from PP&E. A regulatory asset is essentially a deferral of costs that would normally be expensed as incurred. Since the Commission concluded the ETTP costs are not capital, they are by default, O&M expense. However, because the Company expects to realize long-term benefits (e.g. future expense reductions) from these one-time O&M investments in the ETTP, it is appropriate to amortize the expense over the benefit period."[326]

---

[324] See Tr 314-315.
[325] See DTE brief, pages 53-60.
[326] See DTE brief, pages 59-60.

In its reply brief, Staff explains why it does not perceive a significant difference between capitalization and regulatory asset treatment:

> DTE Electric takes issue with Staff's statement that regulatory asset treatment is a distinction with very little difference from capitalization. (DTE Electric's Initial Brief, pp 59-60.) The Company argues, "A regulatory asset is essentially a deferral of costs that would normally be expensed as incurred." (DTE Electric's Initial Brief, p 60.) DTE Electric proposes to amortize the expense over fifteen years. (*Id.*) But, the Company is wrong. Capitalized amounts, whether through property, plant and equipment (PP&E) or through regulatory assets, are included in rate base. Since the Commission denied capitalization through PP&E (rate base treatment) in the past, Staff recommends that the ALJ and Commission deny capitalization through a regulatory asset (rate base treatment) in this case.[327]

This PFD finds Staff's analysis persuasive. While the Commission may authorize the creation of a regulatory asset, DTE has not offered a persuasive reason why the Commission should do so in this case, in order to achieve a ratemaking treatment for the ETTP expenses equivalent to the ratemaking treatment the Commission rejected in Case No. U-17767.

5. Accrued Post-Retirement Liabilities

Mr. Coppola recommended adjusting the working capital component for accrued post-retirement liabilities as shown in his Exhibit AG-29 based on his conclusion that DTE could reduce its average liability balance by obtaining reimbursements from the OPEB trust fund monthly instead of every year:

> In the first of the discovery responses, the Company furnished a reconciliation showing that they plan to reimburse the benefit plans for only $137.3 million of the $198.8 million of benefits paid from the plans. In the second discovery response, the Company indicated that the partial reimbursement is the result of its practice of reimbursing only at year end—presumably for administrative convenience. This differential between the amount of benefits reimbursed and the benefits paid by the Company creates additional working capital of $59.8 million during the projected test

[327] See Staff reply brief, page 9.

> period. The reality, however, is that benefits are paid each month in substantially equal amounts over time and there is nothing stopping the Company from reimbursing itself from the trust funds on a more timely basis so as to minimize working capital requirements.[328]

Ms. Uzenski provided rebuttal testimony on this issue. In its brief, DTE argues that the Attorney General's analysis is inaccurate and incomplete citing Ms. Uzenski's testimony:

> First, Mr. Coppola's proposed adjustment is inconsistent with the Company's historical and projected practice and thus understates the working capital requirement to be incurred by the Company in the projected test year. Second, it ignores that certain benefit payments are not eligible to be reimbursed by the trust funds, so a dollar-for-dollar offset cannot be assumed. Third, Mr. Coppola's implied change in the timing of benefit reimbursement from once annually to monthly ignores the impact such a timing change would have on the Company's short-term debt, which would increase the Company's overall pre-tax cost of capital by 0.03% to 8.26%. The resulting increase in the Company's revenue requirement would largely offset Mr. Coppola's proposed reduction.[329]

The parties' briefs rely entirely on the testimony of these witnesses.[330] As a starting point, Commission is not bound to accept DTE's practice in determining the working account balances if that practice is not reasonable and prudent. Ms. Uzenski testified that not all benefit payments are eligible for reimbursement but did not indicate whether it is a significant percent of the benefit payments that are not eligible for reimbursement. Recognizing that this issue received little attention in this rate case, this PFD recommends that the Commission make no adjustment to working capital in this case but require DTE in its next rate case to specifically address the reasonableness and prudence of its practice of seeking reimbursement from the trust funds only annually.

---

[328] See 6 Tr 1838-1839.
[329] See DTE brief, pages 78-79, citing Uzenski at 4 Tr 852, 866-68, 878-79. Also see DTE reply brief, page 63.
[330] See Attorney General brief, pages 53-54; See DTE brief, pages 78-79, citing Uzenski at 4 Tr 852, 866- 68, 878-79. Also see DTE reply brief, page 63.

6. Interest on Debt

Mr. Coppola also recommended that the interest on debt component of working capital be revised from the historic balance of $56.2 million that DTE used to reflect the increase in long-term debt expected in the projected test year to a balance of $65.1 million. Citing the Schedule D2 in each of Mr. Solomon's Exhibits A-4 and A-11, Mr. Coppola testified:

> These exhibits show long term debt increasing by approximately 15% and interest cost increasing from $240.6 million in 2014 to $278.8 million in the projected test period. Utilizing the information from these exhibits as a starting point in my Exhibit AG-29, page 3, I have developed a projected balance of interest payable of $65.1 million which is higher than the Company's projected test year balance by $8.9 million. This higher level of interest payable is logical given the Company's growing long term debt load and resulting higher interest cost.[331]

In its brief, the Attorney General quotes Mr. Coppola's testimony. DTE did not file rebuttal testimony on this issue and does not appear to have addressed it in its briefs. This PFD recommends that the Attorney General's recommendation be adopted.

7. Taxes Payable

Mr. Coppola also recommended an adjustment to working capital to reflect projected income tax expense attributable to the rate relief anticipated in this case:

> The company's projected tax situation in this rate case in Exhibit A-10, Schedule C8 and C9 shows a taxable base for federal income taxes of negative $95.9 million and for Michigan income taxes of $104.1 million. However, this is before factoring in the rate relief requested in this case of $344.0 million. On page 4 of Exhibit AG-29, I have recalculated the Company's current tax expense based on the company's starting position in its Exhibit A-10 and receipt of the rate relief requested in this case. The result is an expected tax liability of approximately $104 million for the projected test period and tax expense of approximately $13 million which reduces working capital by the same amount.[332]

[331] See 6 Tr 1840.
[332] See Coppola, 6 Tr 1840-41.

In his brief, the Attorney General reiterates Mr. Coppola's testimony.[333]

Mr. Heaphy testified in rebuttal on this issue contending that Mr. Coppola used the "historic balance of $13.0 million" while DTE actually projects tax losses for federal, state and municipal income taxes, and thus the income tax payable balance in working capital should be zero.[334] Mr. Heaphy also testified that Mr. Coppola's recommendation does not reflect the operating loss carry-forward DTE has as shown on its MPSC Form P-521, which will offset an increase in taxable income from rate relief of $344 million.[335] In its briefs, DTE reiterates Mr. Heaphy's testimony.[336] This PFD recommends that the Commission accept DTE's projected working capital tax balance. It is difficult to contemplate the mechanics of an adjustment that requires a determination of the company's revenue requirement that can only be made at the conclusion of the case.

C. Depreciation Reserve

The disputes over the depreciation reserve component of rate base have largely been resolved, and otherwise are related to items discussed above.

1. Depreciation Rates

Staff proposed adjustments to the depreciation reserve to reflect Staff's correction of depreciation rates used in DTE's initial filing. DTE has acquiesced in those adjustments, which also affect depreciation expense as noted in section VII below.

2. Obsolete Inventory

Staff also proposed an alternative approach to obsolete inventory based on the Commission's May 20, 2016 order in Case No. U-18033. DTE has acquiesced to those

[333] See Attorney General brief, page 55.
[334] See 4 Tr 1002-1003.
[335] See 4 Tr 1003.
[336] See DTE brief, page 95; reply brief, pages 80-81.

adjustments to include obsolete inventory as a cost of removal with a corresponding change in depreciation expense as noted below.

3. ETTP Expenses

A remaining adjustment made by Staff relates to Staff's rejection of regulatory asset treatment for certain tree-trimming expenses. Because this PFD recommends above that the Commission not approve the request for regulatory asset treatment for these expenses, the depreciation reserve and depreciation expense amounts should reflect this change. This change should be made consistent with the Commission's final decision in this case.

4. Capital Expense Projections

Finally, Staff adjusted depreciation reserve and depreciation expense to reflect Staff's recommended rate base adjustments. This change should be made consistent with the Commission's final decision in this case.

D. Rate Base Summary

As shown in Attachment B, this PFD estimates that the recommendations discussed above result in a projected rate base of $14,245,747,000, incorporating Staff's recommended distribution operations capital expense allowance rather than the alternative discussed in section A.5 above.

VI.

COST OF CAPITAL

The rate of return component of the revenue requirements determination is designed to meet the constitutional and statutory standards entitling the utility to a fair rate of return on its investment. The Commission in its past decisions and the witnesses testifying in this case recognize as controlling precedent the U.S. Supreme Court cases *Bluefield Water Works Co v Public Service Comm of West Virginia*, 262 US 679; 42 S Ct 675; 67 L Ed 1176 (1923) and *Federal Power Comm v Hope Natural Gas Co*, 320 US 591; 64 S Ct 281; 88 L Ed 333 (1944).

To determine the rate of return to use in setting rates, it is customary to start with the development of an appropriate capital structure, and then to evaluate the appropriate costs to assign each element of the capital structure. The appropriate capital structure is discussed in subsection A below, the cost of debt is discussed in subsection B, and the cost of equity capital is discussed in subsection C. The only element of the rate of return that is disputed in this case is the authorized return on equity. The overall rate of return recommendation is presented in subsection D.

A. Capital Structure

The capital structure used for ratemaking includes as its components long-term debt, preferred stock, and common equity capital, along with short-term debt and other items such as deferred taxes that reflect sources of financing available to the company. Only long-term debt, preferred stock, and common equity capital are considered part of the utility's "permanent" capital, and it is common for capital structures to be shown in exhibits on both a "permanent" basis and on a ratemaking basis. DTE does not have preferred stock so discussions of its permanent capital structure refer only to long-term debt and equity ratios. There is no dispute among the parties that the Commission should use a permanent capital structure with 50% equity, 50% long-term debt, and a ratemaking capital structure with the balances contained in Schedule D1 of Exhibit A-11.

B. Debt Cost

There is no dispute among the parties that the cost of short-term debt used in determining the overall rate of return should be 1.58%, and the cost of long-term debt should be 4.61%.

C. Equity Cost (Return on Equity)

As discussed below, four of the witnesses testifying on the appropriate rate of return on equity for DTE employed a variety of models using groups of proxy companies chosen to be comparable to DTE resulting in a range of estimates of the cost of equity capital. The analysts make their final recommendations by reviewing the range of costs produced by the models along with other information including rates of return authorized by other state commissions and the analysts' views of the relative riskiness of DTE in comparison to the proxy companies. In the discussion that follows, the analysis and recommendations of DTE, Staff, the Attorney General, ABATE, and Walmart are reviewed beginning with a discussion of the proxy companies selected by each of the four analysts using a proxy group (section 1), then reviewing the models used by those analysts (sections 2 through 5), then information on rates of return set by other commissions (section 6), and the general discussion of risk incorporated in the analysts' recommendations (section 7). This PFD's recommendation is provided in section 8.

Dr. Vilbert presented an analysis for DTE recommending a return on equity of 10.5%. He performed a discounted cash flow (DCF) analysis using multiple models, as well as a "risk-positioning" analysis using the Capital Asset Pricing Model (CAPM) and the "Empirical" CAPM (ECAPM), with a variety of inputs. Mr. Megginson presented an analysis for Staff recommending a return on equity of 10%. Mr. Megginson employed the DCF, CAPM, and risk premium models, and considered returns authorized by other state commissions. Mr. Coppola on behalf of the Attorney General, and Mr. Gorman on behalf of ABATE, likewise used DCF, CAPM, and risk premium models, and reviewed rates of return authorized by other state commissions. Mr. Coppola recommended a return of 9.75%, while Mr. Gorman recommended a return of 9.2%. The analysts had differing views on the overall riskiness of DTE in comparison to their proxy groups and differing views on the methods and assumptions used by other analysts, as discussed below. Walmart's witness Mr. Tillman presented an analysis of recent returns on equity authorized by other state commissions and the trend in those returns, which he recommended the Commission consider in setting a return for DTE, although he did not recommend a specific rate of return.

1. Proxy Groups

a. *DTE*

Dr. Vilbert established a proxy group of regulated companies whose primary source of revenues and majority of assets are in the regulated portion of the electric industry. Beginning with all 47 publicly traded electric utilities as classified by Value Line, he identified the following additional criteria for the proxy group:

> The companies must own substantial regulated assets, must not exhibit any signs of financial distress, and must not be involved in any substantial merger and acquisition ("M&A") activities that could bias the estimation process. In general, this requires that over a five year study period and up to the date of the analysis, the sample companies have an investment grade credit rating, a high percentage of regulated assets (greater than 50 percent), no significant merger activity, no dividend cuts, and no other activity that could cause the growth rates or beta estimates to be biased. I also require that each of the sample companies has more than $300 million in reported revenue over the last four quarters of available financial data. Finally, I require that data from S&P or Moody's, Value Line, and

> Bloomberg—each widely known and utilized by investors—be available for all sample companies.[337]

In a footnote, he further explained the merger and acquisition limitation: "This includes pending (but announced) M&A activity, but adjusts for M&A activity that does not appear to bias the beta estimate substantively, (such as small, spaced-out transactions, transactions involving multiple parties or parent drop-downs)."[338]

Information on the resulting 27 proxy companies is presented in Table 2 in his testimony and in Schedules D6.2 and D6.3 of Exhibit A-11. Dr. Vilbert's proxy group includes DTE's parent company, DTE Energy. He compared the sample companies to DTE discussing some financial metrics and discussing DTE's business risk and concluded that DTE has higher than average business risk relative to the sample companies, as discussed in more detail below.

b. Staff

Mr. Megginson testified that Staff looked at five primary criteria in selecting a proxy group:

> 1) each electric company had to have net plant greater than $6.0 billion but less than $20.0 billion to better compare in size and footprint to DTE Electric; 2) each company had to derive approximately 60% of more of its revenues from regulated electric service [;] 3) each utility had to have an investment grade rating within three notches from that of DTE Electric from the two primary rating agencies Standard & Poor's (S&P) and Moody's; 4) each company had to currently be paying dividends to shareholders; and 5) Staff strived to exclude companies that were currently involved in mergers or major corporate buyouts.[339]

Staff's resulting list of 10 proxy companies is shown in Exhibit S-4, Schedule D5, page 2, along with business statistics for the proxy group and DTE. Mr. Megginson testified

---

[337] See 4 Tr 600-601.
[338] See 4 Tr 600 at n 33.
[339] See 5 Tr 1391-1392.

that Staff's proxy group average S&P credit rating is equal to DTE's, while its Moody's average credit rating is below DTE's. Mr. Megginson also objected that DTE's proxy group included DTE Energy. He testified that this "produces a concern since we are trying to obtain a cost of equity estimate for DTE Energy's subsidiaries."[340]

c. Attorney General

Mr. Coppola testified that he used Dr. Vilbert's list of 27 proxy companies as a starting point and excluded DTE Energy because "[it] becomes a self-fulfilling prophecy to establish a benchmark valuation of peer companies when one includes essentially the same company being benchmarked by the peer group."[341] He also excluded several other companies (Allete, El Paso Electric, IDACorp., MGE Energy, Portland General and Otter Tail) on the basis that they are smaller companies not comparable to DTE in size. He testified that stocks of smaller companies with smaller market capitalization tend to trade less frequently and with less trading liquidity than stocks of larger companies and have a customer base and service territories with different risk profiles. He concluded: "For these and other reasons, it is best to use a peer group of companies that more closely matches the size of the operations of DTEE."[342]

d. ABATE

Mr. Gorman testified that he also began with the same proxy group selected by Dr. Vilbert but then excluded three companies due to ongoing merger and acquisition activity. He testified that Dominion Resources announced its intent to purchase Questa in February 2016; NextEra Energy has an ongoing acquisition of Hawaiian Electric; and as of May 2016, Westar Energy is in the process of being acquired by Great Plains

[340] See 5 Tr 1395.
[341] See 6 Tr 1845.
[342] See 6 Tr 1846.

Energy.[343] He testified that ongoing merger activity can distort the market factors used in DCF and risk premium studies including impacting stock prices, growth outlooks, and relative volatility. He testified that his proxy group is reasonably comparable in investment risk to DTE in terms of credit ratings and common equity factors, as discussed in more detail below.[344]

e. Rebuttal

In his rebuttal testimony, Dr. Vilbert objected to Mr. Coppola's exclusion of DTE Energy from the proxy group, labeling his reasoning "flawed" and contending that DTE Energy "is both practically and conceptually distinct from" DTE Electric. He further stated: "It is the risk of DTE Electric that is important, not DTE Energy."[345] He also objected to the exclusion of the smaller companies from Mr. Coppola's sample, calling Mr. Coppola's assertions "vague" and objecting that he had not provided evidence that his concerns applied specifically to these smaller companies.[346]

Dr. Vilbert also testified that he had excluded one of the companies in Staff's proxy group (Eversource) because it was involved in merger and acquisition activity between 2010 and 2012.[347] He address Mr. Gorman's exclusion of other companies on the basis that they were involved in merger activities only in a footnote, asserting that the NextEra proposed acquisition has been canceled and would not meet his threshold requirement because "the Hawaiian Electric purchase represents only about 20% of NextEra's pre-acquistion value," while he uses a 25% cutoff for such activity. He did not address Dominion Reserve, Westar, or Great Plains Energy.

[343] See 6 Tr 1898.
[344] See 6 Tr 1899-1900.
[345] See 4 Tr 657
[346] See 4 Tr 658.
[347] See 4 Tr 656.

f. discussion

The choice of a proxy group is not heavily debated by the parties in their briefs. DTE argues that Mr. Coppola's exclusions of DTE Energy and the smaller companies are "unjustified", citing Dr. Vilbert's testimony.[348] The Attorney General responded to this argument in his reply brief citing Mr. Coppola's testimony and Exhibits AG-32, AG-33, and AG-34.[349]

This PFD concludes that Mr. Megginson's and Mr. Coppola's testimony that DTE Energy should be excluded from the proxy group is persuasive. While the Commission can consider the result of the modeling applied to DTE Energy, DTE Energy should not be included in averages used to derive benchmark rates of return for DTE because it perpetuates any errors in rate setting the Commission may have made in prior cases. Nonetheless, because Dr. Vilbert and Mr. Gorman separately report their results for each company, DTE Energy results can be isolated and analyzed separately. Dr. Vilbert's testimony that DTE Energy and DTE Electric should be viewed as "practically and conceptually distinct" for purposes of this analysis is contradicted by his acknowledgement that DTE Energy obtains at least 80% of its revenues from regulated activities, i.e. primarily from revenues regulated by this Commission.[350]

As to the smaller companies that Mr. Coppola excluded, this PFD concludes that Mr. Coppola's choice was a reasonable one supported by his testimony explaining his understanding of the risks faced by companies of that size.[351] Staff's analysis, however,

[348] See DTE brief, page 21.
[349] See Attorney General reply brief, page 5.
[350] See 4 Tr 603, Table 2, and 4 Tr 602 (EEI classification of Regulated ("R") means "greater than 80% of total assets are regulated.")
[351] See 6 Tr 1846.

most reasonably establishes a minimum and maximum size for the companies in its proxy group.

2. DCF Model

The discounted cash flow (DCF) approach equates the market price of a stock to the present value of the steam of dividend payments an investor expects to receive. The cost of equity is the discount rate necessary to reduce the future cash flows to the current market price.

a. *DTE*

In his DCF analysis, Dr. Vilbert used two DCF models labeled "simple" or "constant growth," and "multistage." He explained that the simple model posits that the cost of capital equals the expected dividend yield plus the (perpetual) expected future growth rate of dividends.[352] He testified that the alternative "multistage" model allows the growth rate to vary over some number of years before reaching a constant growth period.[353] In these DCF models he used forecast earnings growth rates from Bloomberg and Value Line with long-term growth rates for the multistate model based on the long-term GDP forecast from Blue Chip Economic Indicators. His results are presented in Schedule D6.6 of Exhibit A-11 with the average result for the proxy group using the simple model shown as 9.5% on Schedule D6.7 and the average using the multistage model shown as 8.4% on Schedule D6.7. Dr. Vilbert also adjusted his DCF results using the ATWACC approach which is controversial and is discussed separately below.

---

[352] See 4 Tr 621-622.
[353] See 4 Tr 622.

b. *Staff*

Mr. Megginson testified that Staff used the current quarterly dividends, annualized, to determine the dividend yield, and used growth rates based on the average values from Yahoo Finance, Zacks and Value Line. He explained that the formulation of the DCF model that Staff uses is the "constant" model, which adds the average dividend yield to the expected growth rate, but adjusts the dividend yield by a semi-annually compounded projected growth rate.[354] Mr. Megginson testified that the average dividend yield for the proxy group was 3.22% and the average growth rate was 5.45%. He reported the average cost of equity derived for the proxy group using the basic DCF model and the constant model as 8.67% and 8.76%, as shown in Schedule D5 of Exhibit S-4, page 7, with the inputs shown on pages 5 and 6.

c. *Attorney General*

Mr. Coppola presented the results of his DCF analysis in Exhibit AG-32. He testified that he used the high and low prices over 30 trading days for the stock value and the average dividend projection for 2016 and 2017 from the Value Line Investment Survey. He also used Value Line projections of long-term earnings growth rates and Yahoo Finance projected growth in earnings per share for the growth rates in his analysis. He testified that the resulting average cost of equity for the proxy group is 9.4%.

d. *ABATE*

Mr. Gorman also performed a DCF analysis using a "constant growth" formula, a "sustainable growth" formula, and a "multistage" formula. In the constant growth formula he used the weekly high and low stock prices for the proxy companies over a

[354] See 5 Tr 1394.

13-week period through June 10, 2016, and the most-recently-paid quarterly dividend as reported in Value Line annualized and adjusted for next year's growth.[355] He testified that for the growth rate he used the average of analysts' growth rate estimates from Zacks, SNL, and Reuters. He presented the growth rates in Exhibit AB-5 with a proxy group average of 4.86%. He presented his results in Exhibit AB-6 with a proxy group average estimated return on equity of 8.39% and a median of 8.69%.[356]

In his sustainable growth formula he looked to the percentage of retained earnings for each proxy company to estimate their long-term sustainable growth rates derived from the payout ratios as shown in Exhibits AB-7 and AB-8. The average proxy-group sustainable growth rate calculated this way was 4.79%, with a resulting DCF-estimated cost of equity for the proxy group of 8.31%, and with a median for the group of 7.78%.

In his multistage growth model he used different growth rate projections for each of three periods: he incorporated consensus analyst growth expectations for the first five years, a transition period for the next five years that blends these growth rates with the long-term growth rate linearly, and a long-term growth rate thereafter. To determine the long-term growth rate he used the projected long-term growth in GDP of 4.35%, taken from Blue Chip Financial Forecasts.[357] These stages are shown in Exhibit AB-11 along with his multistage DCF estimates for the proxy group with an average of 7.97% and a median of 7.95%. Mr. Gorman presented a summary of the results of all three of his DCF model formulations in Table 5 of his testimony at 6 Tr 1913.

---

[355] See 6 Tr 1901-1902.
[356] See 6 Tr 1902-1903.
[357] See 6 Tr 1907-1912.

e. *Rebuttal*

In his rebuttal testimony regarding the DCF model Dr. Vilbert objected to the other analysts' formulation of the constant growth model. He testified that they used annualized dividend yields and growth rates while he used quarterly dividend yields and growth rates. He testified that Mr. Coppola's model assumes the first dividend is received in one year, while Staff's model assumes that dividends are paid quarterly but increase only annually with growth occurring during the middle of the year. He also testified that Mr. Gorman uses the same dividend yield as Staff but uses the full growth rate.[358] Dr. Vilbert testified that his use of quarterly estimates "correspond[s] to the frequency and timing of actual dividend payments," and further testified "there is no principled reason not to match the period in the DCF model to the actual payment of dividends by the sample companies."[359] He testified that by delaying growth and delivery of dividends in these models the return on equity estimates will be "artificially" lower, although he acknowledged that the difference would be small.

He also objected to Staff and ABATE using a growth rate based on an average of three services, contending that there is substantial overlap of the analyst reports included in Zacks and Yahoo Finance.[360] He testified: "This may bias the growth rate inputs up or down."[361]

[358] See 4 Tr 659.
[359] See 4Tr 659-660.
[360] See 4 Tr 660-661.
[361] See 4 Tr 661.

f*. Discussion*

In its briefs, DTE repeats Dr. Vilbert's criticism of the other analysts' specification of the DCF constant growth model. DTE likewise argues that Staff and ABATE wrongly used multiple sources for their estimates of the growth rates.[362]

Staff responded to both arguments. Regarding the formulation of the constant growth DCF model, Staff cited Mr. Megginson's testimony that use of the semi-annual compounding is a recognized and sound method for estimating growth rates for a proxy group.[363] Staff argues that DTE has not established dividends grow quarterly, while Staff's model reasonably assumes that on average dividends grow once a year in the middle of the year. Staff also argues that FERC uses the same formulation.[364]

This PFD finds Staff's analysis on this point persuasive. There is no basis to reject the results of the models that do not follow the formulation preferred by Dr. Vilbert. As Staff argues, Staff's formulation reasonably assumes that dividends are paid quarterly but grow annually. Moreover, as Mr. Megginson testified and as the Commission has recognized, there is no particular methodology that provides an exact measure of a fair return on equity.[365]

Regarding the use of multiple sources of analysts' projected growth rates, Staff addressed Dr. Vilbert's rebuttal testimony in its initial brief:

> Although the Company argues that there is analyst overlap in Staff's growth estimates, the Company did not establish that any source double counted any particular analysts' estimate. Nor did the Company establish that any source gave more weight to certain analysts' estimates than in others. The Company merely speculates that there was analyst overlap

[362] See DTE brief, pages 26-27.
[363] See Staff brief, pages 35-36, citing 5 Tr 1394.
[364] See Staff brief, page 36.
[365] See 5 Tr 1391.

> and that "some analysts *may* report to several services." (4 TR 661, emphasis added.) [366]

This PFD also finds Staff's argument on this point persuasive, and rejects the claim that Staff's and ABATE's growth rate estimates are improper because they rely on multiple composite sources that might include some of the same analysts. There is no reason on this record to conclude that the group of analysts who may be contributing estimates to more than one source is itself biased.

3. CAPM

The Capital Asset Pricing Model is also frequently used in estimating the cost of equity capital. It posits that because investors can manage certain risks with a diverse portfolio, the required return for a security consists of a risk-free rate plus a market premium that is proportional to the degree of non-diversifiable or systematic risk of the security. The non-diversifiable risk is designated by beta (β), which indicates the relative risk of a security as compared to the market as a whole. All four analysts performed one or more versions of a CAPM analysis.

a*. DTE*

Dr. Vilbert's CAPM analysis, which he refers to as his "risk-positioning" analysis, is significantly more complicated than that of the other analysts. Dr. Vilbert begins his analysis with a discussion of his view of current financial markets that leads him to make certain adjustments to the CAPM model inputs. He testified that the cost of equity capital relative to the cost of risk-free government debt is higher than it was before the financial crisis of 2008:

> Although economic conditions have improved substantially since the height of the crisis, uncertainty remains in the capital markets due, in part,

366 See Staff brief, page 36.

> to the disappointing rate of economic growth, particularly in Europe and Asia. Economic growth in Europe remains anemic with the ongoing fallout from the sovereign debt crisis. There is increasing uncertainty of the effects of the ongoing and recent conflicts in the Middle East and concerns about the strength of the Chinese economy. Although long-term government bond yields have risen somewhat since 2012, they have stagnated over the past year and remain at low levels by historical standards.
>
> As a result, bond yield spreads remain higher than before the credit crisis, both for riskier assets as well as for less risky investments such as investment grade-rated utility debt.[367]

He testified to his opinion that uncertainty in global capital markets has "served to increase risk aversion among U.S. investors."[368] Also discussing the U.S. economy and the policies of the Federal Reserve Bank, he testified that these circumstances heighten the uncertainty.[369] Dr. Vilbert testified that the increased market risk premium is demonstrated by the increase in yield spreads between utility bonds and government bonds, before and after the 2008 crisis. He displays historical yield spreads in his Table 1 for both A-rated and BBB-rated utility bonds. From this information, he concludes that the yield spread on A-rated bonds has increased by 75 basis points.

He hypothesizes that this 75-basis-point increase is due to a combination of the increase in the "systematic risk premium" and the downward pressure on the yields of government debt caused by increased risk aversion, which he calls the "flight to safety". On this premise, he allocates the 75 basis points between an increase in the risk-free rate and an increase in the market risk premium in three ways, leading to three scenarios that he uses in his analysis. Each of the three scenarios provide for a 75-basis-point increase to the return otherwise predicted for a security with a beta of

---

[367] See 4 Tr 574.
[368] See 4 Tr 583.
[369] See 4 Tr 588.

.25, to reflect an A-rated utility bond.[370] Dr. Vilbert depicted the two types of changes to the security market line, a change in intercept with the same slope and an increase in the slope, in his Figure 4 at 4 Tr 599.

In considering what risk-free rate to use, prior to making his risk premium adjustments, he concluded that the 20-year Treasury bond yield as reported by Bloomberg as of the date of his analysis would not be applicable to the projected test year running from August 2016 to July 2017. He testified that he started with the 2.7% yield that Blue Chip Indicators forecast to be in effect in 2016, and adjusted it upwards by 30 basis points, to derive a risk-free rate of 3.0%.[371] He also testified that he would ordinarily use a market risk premium of 6.5% based on his review of the academic literature.[372]

The risk-free rate of 3% and the market risk premium of 6.5% form the basis for the adjustments to reflect his three scenarios. First, he posits that the 75-basis-point yield spread increase discussed above increases only the risk-free rate, resulting in "scenario 1" with a risk-free rate of 3.75% and a market risk premium of 6.5%. Second, he posits that the 75-basis point yield spread increase raises the risk-free rate by only 50-basis points, resulting in "scenario 2" with a risk-free rate of 3.5% and a 1% (100 basis point) increase in the market risk premium to 7.5%. Third, for "scenario 3", he posits that the 75-basis point yield spread increase raises the risk-free rate by only 25 basis points, resulting in a risk-free rate of 3.25% and a 2% (200 basis point) increase in the market risk premium to 8.5%.[373]

[370] See 4 Tr 594-595.
[371] See 4 Tr 611-612.
[372] See 4 Tr 614.
[373] See 4 Tr 618-619.

In addition to using these three scenarios in the standard CAPM formulation, Dr. Vilbert also testified that it is preferable to use a different version of the Capital Asset Pricing Model, the "Empirical Capital Asset Pricing Model" (or ECAPM), to reflect empirical observations regarding the relationship between risk and return:

> The CAPM has not generally performed well as an empirical model, but its shortcomings are directly addressed by the ECAPM. Specifically, the ECAPM recognizes the consistent empirical observation that the CAPM underestimates (overestimates) the cost of capital for low (high) beta stocks. In other words, the ECAPM is based on recognizing that the actual observed risk-return line is flatter and has a higher intercept than that predicted by the CAPM. The alpha parameter (α) in the ECAPM adjusts for this fact, which has been established by repeated empirical tests of the CAPM.[374]

Dr. Vilbert presented another drawing of the security market risk line to illustrate the relationship between the CAPM and ECAPM.[375] As he explained and as shown on this drawing, the ECAPM has the effect of increasing the indicated return for lower-risk securities, those with betas less than 1, and decreasing the indicated return for higher-risk securities, those with betas above 1. In order to reflect the empirical observations, he testified that he used two different values of alpha in the equation for the ECAPM, .5% and 1.5%, which he also refers to as "sensitivities". Using the ECAPM with these sensitivities, he derived two additional sets of results that he labeled ECAPM (0.5%) and ECAPM (1.5%), with each set of results including estimated returns for each proxy company under each of the three scenarios discussed above. He used betas taken from Value Line for each model and scenario. The results are presented in Schedule D6.10 of Exhibit A-11.

[374] See 4 Tr 617-618. The ECAPM equation is: $r_s = r_f + \alpha + \beta_s \times (MRP - \alpha)$.
[375] See 4 Tr 618.

As noted above, Dr. Vilbert adjusts these results further using his ATWACC method which is controversial and is discussed below. While Dr. Vilbert does not report the average unadjusted returns for his CAPM and ECAP analysis directly, he presented the individual results for each proxy company, and Mr. Gorman presented the averages.[376] For his CAPM analysis, the average results are 8.7%, 9.2, and 9.7% for scenarios 1, 2 and 3 respectively. For the ECAPM (0.5%) the average results are 8.8%, 9.3%, and 9.9% for scenarios 1, 2 and 3 respectively. For the ECAPM (1.5%), the average results are 9.0%, 9.6% and 10.1% respectively.

b*. Staff*

Mr. Megginson testified that Staff's CAPM modeling for the proxy group was based on a market risk premium of 6.3% based on the latest edition of the Ibbotson Associates Yearbook. He testified that Staff looked at both the time period 1926 -2015 and 1952-2014, and used the latter time period in its analysis:

> The latter period covers a number of economic cycles yet excludes the periods of non-market based administered interest rates that were not tied to market forces.[377]

Mr. Megginson also testified that Staff's analysis used a risk-free rate of 3.10% based on Value Line's long-term government bond forecast and used betas also taken from Value Line.[378] Mr. Megginson explained that Value Line measures a 60-month average raw beta on a weekly basis and then adjusts that raw beta by a convergence factor towards the market beta of 1. He testified that the results of Staff's analysis showed an average cost of equity of 8.01% for the proxy group, which has an average beta of .78.

[376] See 6 Tr 1932.
[377] See 5 Tr 1396-1397.
[378] See 5 Tr 1397.

Mr. Megginson also critiqued DTE's analysis. First, he objected to the increased risk premiums in Dr. Vilbert's scenarios 2 and 3. He testified that the first scenario appears reasonable based on the market risk premium's alignment with historical observation but that scenarios 2 and 3 use market premiums that are too high.[379] Second, he objected to Dr. Vilbert's use of the ECAPM formulation. He testified that there are several concerns regarding this model, including its use of Value Line betas instead of raw betas, citing the PFD issued in Case No. U-17735 that found the combination to be double-counting.[380] He testified that the ECAPM results Dr. Vilbert derived are higher than his CAPM results increasing the average to 8.8% and 9.0% in scenario 1 to 9.3% and 9.6% in scenario 2, and to 9.8% and 10.1% in scenario 3. He recommended that the Commission reject the ECAPM in its entirety.[381]

c*. Attorney General*

Mr. Coppola presented his CAPM analysis in Exhibit AG-33. He used a risk free rate of 3.25% noting that the current rate for 30-year Treasury bonds as of early June was 2.6%. He testified: "[S]entiment in the market is fairly universal that interest rates will rise with the Federal Reserve Bank winding down its "quantitative easing" efforts and the United States economy continuing to improve."[382] Mr. Coppola also testified that he used betas taken from Value Line and an historical market premium of 7.0% based on the Ibbotson Classic Yearbook through 2014. The average cost of equity derived for the proxy group in his CAPM study was 8.47%.

---

[379] See 5 Tr 1398.
[380] See 5 Tr 1399.
[381] See 5 Tr 1399.
[382] See 6 Tr 1850.

Mr. Coppola took issue with Dr. Vilbert's use of higher market risk premiums of 7.5% and 8.5% in his scenarios 2 and 3.

d. *ABATE*

Mr. Gorman presented a CAPM analysis. Noting that the current 30-year Treasury bond yield was 2.6%, he used the Blue Chip Financial Forecasts projected 30-year Treasury bond yield of 3.4% in his analysis, explaining the importance of using a long-term rate. [383] He also testified that the average beta for his proxy group is 0.74. And, he explained that he derived his market risk premium estimates of 6.0% and 7.8% from information in the Duff & Phelps' 2016 Valuation Handbook. The 7.8% estimate reflects the difference between historic real market returns over the time period 1926-2015, adjusted for inflation, and the risk-free rate of 3.4%. The 6.0% estimate is based on the difference between the total market return on the S&P 500 over the same time period, 12%, and the total return on long-term Treasury bonds over the same time period, 6%.[384] He testified that Duff and Phelps also estimate the market risk premium as in the range of 5.5% to 6.9%, explaining their analysis in further detail.[385]

Mr. Gorman presented the results of his CAPM analysis in his Exhibit AB-18, with a 7.86% rate of return derived using the low market risk premium, and a 9.2% rate of return derived using the high market risk premium. Using a weighting similar to his DCF analysis with 75% weight given to the high result and 25% to the low result, he distilled his CAPM analysis to a return on equity of 8.9%.

Mr. Gorman also objected to Dr. Vilbert's ECAPM analysis arguing that his empirical adjustment is inconsistent with his use of adjusted beta from Value Line. He

---

[383] See 6 Tr 1922.
[384] See 6 Tr 1923-1924.
[385] See 6 Tr 1924-1925.

testified that the Value Line adjustment increases betas below 1 and decreases betas above 1:

> I am not aware of any research, that was subject to peer review, that supports Dr. Vilbert's proposed use of an adjusted beta in an ECAPM study. Therefore, Dr. Vilbert's proposal to use an "adjusted" beta, such as those provided by Value Line, in an ECAPM analysis is not based on sound academic principles, is not supported by the academic community, and should be rejected.[386]

e*. Rebuttal*

Dr. Vilbert objected to Staff's use of a market risk premium of 6.3%. He testified that Staff reasonably relied on Ibbotson data but testified that Staff should have used all data available from 1926 forward rather than from 1952 forward to avoid bias.[387] Dr. Vilbert also objected to Mr. Gorman's use of a market risk premium value of 6% as one of the two values he used. He testified that it is "improperly derived" because it considers the total return on government bonds rather than only the cash payments which he characterized as the only "risk-free" element of the return.[388] He presented a chart showing historical averages over multiple periods and testified that his own choices of 6.5%, 7.5% and 8.5% are reasonable. Dr. Vilbert testified that if the other analysts had used those values in their analysis, Mr. Megginson's results would have been 15 to 165 basis points higher, Mr. Coppola's would have been 40 to 115 basis points higher, and Mr. Gorman's would have been 30 to 185 basis points higher.[389]

Dr. Vilbert also objected that the other analysts did not use the ECAPM model. Reviewing his earlier testimony on the basis for this model, he also presented in Schedule X1 of his Exhibit A-34 what he described as a "discussion of the academic

[386] See 6 Tr 1938-1939.
[387] See 4 Tr 663.
[388] See 4 Tr 664.
[389] See 4 Tr 664-665.

tests of the CAPM that provides an estimate of the size of the adjustment [α] that resulted from the tests."[390] He acknowledged that the articles were "older" but testified that "repeated tests have generated the same result so current research has turned to developing a replacement model that better fits the empirical data." In this context, Dr. Vilbert disputed Mr. Megginson's and Mr. Gorman's testimony that Value Line adjusted betas should not be used with the ECAPM model, characterizing them as two fundamentally different and complementary adjustments.[391] He asserted that the backward-looking empirical tests of the CAPM that led to the ECAPM did not require adjusted betas and asserted that the beta adjustments are forward looking based on the empirical observation that historical measurements of a firm's beta are not the best predictor of what that firm's systematic risk will be going forward. He also presented a drawing to illustrate his testimony regarding the backward nature of the ECAPM adjustment and the forward nature of the beta adjustment. Dr. Vilbert testified that making an ECAPM adjustment with alphas of 0.5% and 1.5% would add 12 to 35 basis points to Staff's, the Attorney General's, and ABATE's CAPM results.[392]

f*. discussion*

The briefs of the parties closely track the testimony of their witnesses regarding the appropriate market risk premium to use and the use of the ECAPM.

Staff defends its use of the 1952-2014 time period from the Ibbotson data in estimating the market premium, citing Mr. Megginson's testimony that: "The latter period covers a number of economic cycles yet excludes the periods of non-market based

[390] See 4 Tr 666.
[391] See 4 Tr 667.
[392] See 4 Tr 671.

administered interest rates that were not tied to market forces."[393] Staff also argues that DTE's use of a market risk premium of up to 8.5% is excessive. Staff argues that Dr. Vilbert's manual adjustments mask data that reflects market conditions:

> Dr. Vilbert ignores the logical implications of his own testimony – that interest rates elsewhere are so low, even negative, that investors are looking to any relatively safe investment that has "some kind of a reasonable rate of return that's not negative." The logical implication, of course, is that utilities need not court investors with increased rates of returns, as return rates that are even substantially lower than current return rates are still very favorable compared to foreign markets.[394]

In its reply brief, DTE characterizes this argument as agreeing with the facts underlying Dr. Vilbert's calculation but disagreeing with his professional opinion. DTE further responds: "Staff similarly chose to disregard the long-term (1926-2014) historical MRP average of 7.0% in favor of a 6.3% MRP average from 1952-2014."[395] This PFD finds that Staff's use of the latter time period of Ibbotson data is reasonable and has been vetted by the Commission and approved multiple times.

This PFD finds that use of a market risk premium of 8.5% is excessive. Dr. Vilbert's testimony attributing the difference in yield spreads to an increase in risk aversion is not persuasive. For several years, it has been acknowledged that the risk-free interest rates reflected by Treasury bond yields are artificially low and expected to rise. Thus, this Commission has used projected risk-free interest rates above then-current rates when evaluating the cost of equity. There is no evidence on this record that investors did not similarly expect the risk-free rate to rise when purchasing utility bonds. In this case, all witnesses testifying on this issue expect the risk-free rate to rise.

---

[393] See Staff's brief pages 37-38.
[394] See Staff brief, pages 38-39.
[395] See DTE reply brief, page 12.

Additionally, this PFD finds that the use of the ECAPM is inconsistent with the use of adjusted betas. Mr. Gorman's and Mr. Megginson's testimony are persuasive that it is improper and duplicative to use both Value Line adjusted betas and the ECAPM adjustment of the "security-market line". Both adjustments are based on observed relationships between the systematic risk of a stock as measured by its beta and market returns rather than theory. Both adjustments have the effect of increasing the expected return for stocks with unadjusted betas below 1 and decreasing the expected return for stocks with unadjusted betas above 1. When challenged by Mr. Gorman, despite lengthy rebuttal testimony, Dr. Vilbert did not provide a peer-reviewed paper stating that it is appropriate to use both forms of adjustment in predicting returns.

An independent reason to reject the empirical CAPM adjustment is that it contradicts Dr. Vilbert's theory that the market-return line has shifted to a line with a steeper slope as a result of the flight to safety, i.e. that for any given beta above zero, investors now demand higher returns. If one were to superimpose his Figure 4 at 4 Tr 599 with his Figure 5 at 4 Tr 618 it would show the market risk line simultaneously made steeper and more flat.

4. Risk Premium

The risk premium approach attempts to compute the cost of equity by comparing common equity returns to risk-free returns. Only Staff, the Attorney General, and ABATE presented a traditional risk premium analysis as described below. Dr. Vilbert's criticisms of their analyses are also discussed as well as his rebuttal analysis.

a. *Staff*

Staff used a risk premium approach to estimate the required return on equity evaluating the spread from historical electric utility realized stock returns and composite utility bond yields and applying this premium to current utility bond yields. Mr. Megginson testified that the equity returns and bond yield estimates were taken from Mergent Public Utility Manual & Bond Record from 1932 through 2002, and from the Dow Jones Utilities index from 2003 to 2015, as shown in his Exhibit S-4, Schedule D5, page 10. He testified that using this data the historical risk premium was 4.45%. In addition, he testified that he also used a survey of the estimated yield spreads of stocks relative to bonds provided by academics, analysts, and companies, and published in the 2015 Edition of *Equity Risk Premiums: Determinants, Estimation and Implications*, by Aswath Damodaran. Using the average estimated spread of 5.37% from this publication, Mr. Megginson applied this risk premium to the long-term utility bond yields from Value Line for A-rated and BBB-rated bonds, 3.96% and 4.50% respectively, to derive the risk premium estimated returns of 8.41% and 8.95% respectively. These results are shown in Exhibit S-4, Schedule D5, page 12.[396]

b. *Attorney General*

Mr. Coppola presented his risk premium analysis in Exhibit AG-34. He testified that he used a 4.25% historical spread of electric utility common stock returns relative to utility bonds; he used the 1.45% average of the 1.25% spread of A-rated bonds to Treasury bonds and the 1.65% spread of BBB-rated bonds relative to Treasury bonds in

[396] See 5 Tr 1400-1401.

2015; and he used the same 3.25% risk-free rate he used in his CAPM analysis. The resulting estimated return on equity was 8.95%.[397]

c. *ABATE*

Mr. Gorman also used a risk premium model in his analysis looking at two different forms of risk premium. In his first analysis, his risk premium is the difference between the required return on utility equity investments, measured by regulatory commission authorized rates of return on equity, and Treasury bonds for each year of the period 1986 through March 2016. In his second analysis, he looked at the risk premium as measured by the difference between regulatory commission authorized returns and A-rated utility bond yields as measured by Moody's over the same time period. He testified he selected this time period because the market-to-book ratios for utility stocks over that period have consistently been above 1, as shown in Exhibit AB-12. The results of his analyses, also shown as five-year and ten-year rolling averages of the measured risk premiums, are presented in his Exhibits AB-13 and AB-14. The results shown for the first risk premium estimate range from a low of 4.25% to a high of 6.71%; the results shown for the second risk premium estimate range from a low of 2.88% to a high of 5.53%.

To reduce the ranges of values produced in this analysis to specific risk premium values to use in determining the cost of equity, Mr. Gorman used a weighted average with a 75% weighting to the high-end value of each range of risk premiums and a 25% weighting to the low-end value of each range of risk premiums to produce a risk premium for Treasury bond yields of 6.1% and a risk premium for utility bond yields of 4.87%. Mr. Gorman added the projected 30-year Treasury bond yield of 3.4% from

[397] See 6 Tr 1853.

Blue Chip Financial Forecasts to his first risk premium of 6.1% to produce an estimated cost of equity of 9.5%. He added the current 13-week average Baa-rated utility bond yield of 4.69% to his second risk premium of 4.87% to produce an estimated cost of equity of 9.6%.[398]

d*. Rebuttal*

Mr. Gorman objected to one of Mr. Megginson's risk premium analyses contending that the risk premium of 5.37% taken from the 2015 Equity Risk Premium (ERP) study published by Aswath Damodaran is intended as a risk premium for the stock market as a whole, not a lower-risk electric utility. He recommended that the risk premium be adjusted by a beta representing the systematic risk of utility stocks relative to the overall market.[399] Using this approach, he derived a revised risk premium of 4.45%. He applied this to Mr. Megginson's bond yields of 3.96% for A-rated bonds and 4.5% for BBB-rated bonds to derive return estimates of 8.39% and 8.95%.[400]

Dr. Vilbert also took issue with the risk premium analyses in his rebuttal. He testified that the method does not have strong support in financial theory and should not get much weight, objecting that it assumes the proxy for the estimated risk premium will remain unchanged.[401] He testified that Staff's analysis inconsistently used a 60-year time period to estimate the spread between market returns and bond yields and only a 20-year or 30-year time horizon for the risk-free bond yields. He also objected to the steps used in Mr. Coppola's analysis.[402] Dr. Vilbert also presented an additional analysis in his rebuttal testimony. He testified that there is an inverse relationship

---

[398] See 6 Tr 1917-1920.
[399] See 6 Tr 1951.
[400] See 6 Tr 1952.
[401] See 4 Tr 672.
[402] See 4 Tr 672-673.

between risk premiums as measured by returns on equity granted by utility regulatory commissions and Treasury bond yields and constructed a regression analysis to demonstrate the magnitude of this relationship.[403] From his regression results, also presented in his Schedule X2 of Exhibit A-34, and using a projected Treasury yield of 3.65% he estimated a cost of equity of 10.3%.

e. *Discussion*

In its brief, Staff argues that Dr. Vilbert mistakenly criticized Staff's risk premium analysis, asserting that Staff's analysis obtained market return averages and utility bond returns over the same time period. In a footnote to its brief, at page 22, DTE argues that Dr. Vilbert's regression analysis "corrected . . . downward bias" due to the current environment of very low interest rates with his risk premium regression and estimate.[404]

This PFD recognizes that the Commission has considered rates of return from various risk premium approaches in determining the cost of equity for decades, and therefore recommends that the Commission continue to consider the results of these analyses.

Staff also addresses Mr. Gorman's critique of Staff's risk premium analysis on the basis that it uses general market returns, disputing that a beta adjustment is required. Staff argues that an adjustment would be wrong because the broad group of stocks could also include utility investments.[405] Although Staff does not have additional information regarding the risks reflected in the ERP source, the resulting return on equity can be considered, while keeping the context in mind.

[403] See 4 Tr 673-674.
[404] Also see DTE reply brief, page 9 at n 12.
[405] See Staff brief, page 45.

5. <u>After-Tax Weighted Average Cost of Capital</u>

Another issue presented by the analysts' cost of capital recommendations involves DTE's use of the After-Tax Weighted Average Cost of Capital (ATWACC) formulation to derive a recommended cost of capital for DTE. DTE's testimony and the critiques of other witnesses are discussed below.

a. DTE

As noted above, Dr. Vilbert did not utilize the average returns on equity generated for the proxy group as a result of his CAPM/ECAPM and DCF analyses. Instead, he used those results and certain other assumptions to calculate the "After Tax Weighted Average Cost of Capital" (ATWAAC) for each of those proxy companies for each of his model formulations, took the average ATWAAC for all the proxy companies, and used that average to back out a return on equity for DTE, using its ratemaking capital structure and an assumption about its debt costs.

Dr. Vilbert discussed this approach testifying that his adjustment is necessary:

> The ATWACC is one of several procedures in my analysis; it is important because it allows a comparison between the sample companies' costs of capital estimates and the cost of capital for DTE. Two otherwise identical companies with different capital structures will typically have different costs of equity because the risks to equity holders depend on the financial leverage (i.e., the amount of debt in the capital structure of the company). This makes it difficult to compare cost-of-equity estimates among companies that have different capital structures. The effect of varying financial leverage on the risk-return tradeoffs of companies means that simply averaging individual cost-of-equity estimates across a sample generally does not provide meaningful information about an appropriate representative cost of capital for the industry. Thus it is generally incorrect to compute a sample average return on equity when estimating the cost of capital. However, two otherwise identical companies with different capital structures will generally have comparable ATWACC values. The "apples to apples" comparability of ATWACC across companies with different

capital structures makes it a consistent measure of the representative cost of capital in an industry.[406]

In making this adjustment for his CAPM/ECAPM analysis, he computed the after-tax weighted cost of capital for each proxy company using that company's market-value capital structure, the equity returns developed using the CAPM, ECAPM (0.5%), and ECAPM (1.5%) models for each of the three scenarios, and a cost of long-term debt he assigned to each proxy company as discussed in more detail below.[407] A footnote to his schedule D6.11 and his Schedule D6.4 indicate that the capital structures for each company are based on a five-year average. These values, along with averages, are presented in Schedule D6.11 of Exhibit A-11. Once the proxy group average ATWACC is computed for each model and each scenario for a total of nine averages, Dr. Vilbert determined a corresponding cost of equity that would be required to be applied to DTE's book value capital structure to produce the same overall weighted average cost of capital. To perform this calculation he also used a cost of debt of 4.8% for DTE, and a tax rate of 38.9%.[408] The results as presented in Schedule D6.12 of Exhibit A-11 are: 9.3%, 9.8%, and 10.4% for the CAPM model, scenarios 1, 2 and 3 respectively; 9.4%, 10.0%, and 10.5% for the ECAPM (0.5) model, scenarios 1, 2 and 3 respectively; and 9.7%, 10.2%, and 10.8% for the ECAPM (1.5) model, scenarios 1, 2 and 3 respectively.

In making the ATWAAC adjustment for his DCF analyses, he computed the after-tax weighted cost of capital for each proxy company using that company's market-value capital structure, the equity returns developed using the constant growth

[406] See 4 Tr 579.
[407] See Schedules D6.11, D6.4, and D6.7 of Exhibit A-11. Dr. Vilbert includes a tax rate of 38.9% as part of the cost of equity, and he also recognizes that some of the proxy companies have preferred stock.
[408] See Exhibit A-11, Schedule D6.12.

and multistage DCF models, and slightly different debt costs. A footnote to his Schedule D6.7 and his Schedule D6.4 indicate that the capital structures for each company were based on the 2015 third-quarter values reported by Bloomberg.[409] Another footnote to his Schedule D6.7 indicates that he excluded the four companies with the lowest return on equity estimate from his constant growth DCF analysis because the estimated costs of equity were below or too close to the estimated cost of debt.[410] As with the CAPM/ECAPM results, he used the average of the after-tax weighted average cost of capital constructed for each proxy company for the constant growth and multistage DCF models to back out a cost of equity capital for DTE, using DTE's book value capital structure, a cost of debt of 4.8%, and a tax rate of 38.9%. As shown in Schedule D6.8 of Exhibit A-11, the results for the DCF analyses as adjusted by the ATWACC approach are 10.6%[411] for the constant growth DCF and 9.3% for the multistage DCF.

b. Staff

Mr. Megginson took issue with Dr. Vilbert's ATWACC method, arguing that the formula calls for the use of BBB-rated debt costs when the proxy group's average cost of debt appears to be BBB+ or higher and DTE Electric's debt is rated even higher by S&P.[412] He also testified: "[T]he ROE estimate is established by using a rather complex calculation that takes into account the average after-tax market value cost of capital of the electric proxy group, plus DTE Electric's income tax rate, and the Company's debt and equity percentages but not the Company's cost of debtor at least a

[409] The equity ratios in the capital structures used in the DCF ATWACC calculations are generally higher than the equity ratios in the capital structures used in the CAPM/ECAPM calculations, averaging 59% for the DCF calculations and 56% for the CAPM/ECAPM calculations.
[410] See Exhibit A-11, Schedule D6.7, page 1.
[411] Correcting an apparent calculation error for the simple DCF would reduce the result from 10.6% to 10.5%.
[412] See 5 Tr 1395.

cost of debt associated with DTE Electric's credit rating." He recommended that the Commission give no weight to DTE's return on equity estimate, or consider instead the company's unadjusted analysis, before the application of the ATWACC modification.[413]

c. Attorney General

Mr. Coppola testified that Dr. Vilbert's use of the ATWACC produced an after-tax weighted cost of capital of 6.7% by reference to an average capital structure of the proxy companies that is 59% common equity and 41% long-term debt, reflecting the market values not the book values, of equity and debt. Testifying that Dr. Vilbert then recalculates the cost of equity based on a 50%-50% capital structure, Mr. Coppola testified that he disagreed with the approach:

> First of all, the result of this ATWACC methodology simply reflects the currently high common equity market to book ratios of the peer group of companies. This is primarily the result of (1) regulatory commissions moving slowly to reduce authorized ROEs as interest rates have fallen and (2) investors buying more utility stocks for dividends because they cannot find alternative low risk investments with cash returns. This is the result of the Federal Reserve maintaining a low interest rate policy which Dr. Vilbert also discusses in his testimony. Second, to my knowledge, the use of ATWACC methodology to boost basic DCF results has not been embraced by other state regulatory commissions in the United States.[414]

d. ABATE

Mr. Gorman also testified that he disagreed with Dr. Vilbert's use of the ATWACC adjustment. He presented a table at 6 Tr 1932 showing the unadjusted average results of Dr. Vilbert's DCF and CAPM/ECAPM analysis, his recommendation following the use of the ATWACC, and the .6% to 1.1% magnitude (60 to 110 basis points) of the resulting increases. He further testified that the ATWACC adjustment moves his range of results from a range of (8.4%, 10.1%) to a range of (9.4%, 10.8%).

[413] See 5 Tr 1395.
[414] See 6 Tr 1848.

Mr. Gorman testified that this adjustment is severely flawed and should be rejected:

> Dr. Vilbert proposes to adjust his DCF and CAPM model results for the difference in financial risk based on the proxy companies' market value of common equity, compared to DTE Electric's regulated (i.e., book value) common equity.
>
> Dr. Vilbert's general assessment is that a ROE should be higher based on a regulatory capital structure because this capital structure has more financial risk than does the common equity valued at market stock prices. He is in effect suggesting that firms have a different level of financial risk if one is observing its market value capital structure relative to the regulatory or book value capital structure. [415]

He explained his objections to an additional adjustment for financial risk:

> This is flawed for several reasons. First, the Company only has one level of financial risk, not two. Investors do not assess a different amount of financial risk for market and book common equity valuation. Rather, financial risk is a singular risk factor which describes the utility's financial capital structure, cash flow strength to support financial obligations, and default provisions in its financial obligations.
>
> Dr. Vilbert's belief that there are two levels of financial risk is simply neither supported nor rational. Indeed, it is contradicted by data used by independent market participants to assess investment risk and credit standing. For example, S&P and *Value Line* provide general assessments of the financial and operating (or total investment) risks to the market investors. S&P does this in terms of rating the credit quality of the utility, based on the utility's ability to produce cash flows adequate to meet its book value financial obligations. S&P assesses a company's risk of failing to meet its financial obligations and is a direct assessment of a company's financial risk.
>
> *Value Line* on the other hand provides information to the market participants to help them assess the total investment risk including both financial risk and business risk for the utilities and other stock investments. The data *Value Line* provides to investors concerning these investment risk characteristics relates to book value risk factors including book value capital structure, book value cash flows, and book value earnings. All these book value factors are then used by investors to assess investment risk which allows them to derive market value stock prices. The book value parameters are an integral part of assessing risk and allowing

[415] See 6 Tr 1934.

investors to produce market valuations. There is not a difference between book value risk and the market value risk. Rather, the book value and market value risks are interconnected to one another, and lead to a single finding of financial risk.

Both *Value Line* and S&P assess a company's financial risk based on its book value leverage, book value cash flows, and the earnings on its book value common equity. These independent published sources of information that investors rely upon do not equate financial risk to market value capital structures. This is most likely because a company's ability to produce earnings and cash flows that are adequate to meet its debt service obligations, to produce earnings that are capable of paying dividends and growing dividends over time are based on book value financial factors.[416]

He also characterized it as poor regulatory policy:

The ATWACC methodology is poor regulatory policy and should be rejected for several reasons.

1. First, it does not produce clear and transparent objectives for management to use that will accomplish the objective of minimizing its overall rate of return while preserving its financial integrity. Therefore, a regulatory commission cannot oversee the reasonableness and prudence of management decisions in managing its capital structure. Under the ATWACC theory, management's decisions to manage its capital structure can be skewed by changes in market value which change the market value capitalization mix. Management simply has no control over the market value capital structure, but it does have control over the book value capital structure. As such, setting the rate of return and measuring risk based on book value capital structure creates a more transparent and clear path for regulatory oversight of management's effort to maintain a balanced and reasonable capital structure.

2. Second, the ATWACC introduces significant additional instability into the utility's cost of service and tariff rates. Book value capital structure weights permit the utility to hedge or lock-in a large portion of capital market costs in arriving at the rate of return used to set rates. This rate of return cost hedge stabilizes the utility's cost of service, which in turn helps stabilize utility rates. A stable method of setting rates also allows investors to more accurately assess the future earnings and cash flow outlooks for the utility, which will reduce the business risk of the utility. The ATWACC, on the other hand, will produce an overall rate of return which will change based on both changes to market value capital structure weights and also

[416] See 6 Tr 1934-1935.

based on changes to market capital costs. Hence, a major component of the cost structure of the utility (i.e., the overall rate of return) will vary based on market forces from rate case to rate case. This rate of return variability will introduce significant instability in the utility's cost of service (via rate of return changes) and hence instability in tariff rates. Introducing additional instability in the utility's cost structure and rates will not benefit either investors or ratepayers.

3. The ATWACC unnecessarily increases rates to produce an excessive ROE opportunity for utility investors. Inflating utility's rates to provide this excessive earnings opportunity is unjust and unreasonable and should be rejected.[417]

Further, he cited examples of jurisdictions rejecting this approach.[418]

e. Rebuttal

In his rebuttal testimony Dr. Vilbert addressed criticism of his ATWACC adjustment by Mr. Megginson, Mr. Coppola, and Mr. Gorman. He testified at length regarding financial leverage and how it works. He reviewed his direct testimony regarding this adjustment and further testified:

I use the ATWACC simply to compare the estimated ROEs from the sample on an apples-to-apples basis. Computing the ATWACC for the sample companies allows the analyst to isolate the contribution of non-diversifiable *business risk* to the cost of capital from the confounding influence of financial risk, thus allowing for an "apples to apples" comparison of required overall returns among the sample companies and the subject companies.

Simply put, a sample company with higher business risk and lower financial risk may yield exactly the same investor-required cost of equity as a lower business risk/higher financial risk company. However, an average of the two will not produce an accurate cost of equity for the Company except by accident. This remains true no matter how large the sample group of companies unless the Company has *exactly* the same capital structure as the average of a statistically large sample.[419]

[417] See 6 Tr 1935-1936.
[418] See 6 Tr 1936-1937.
[419] See 4 Tr 682-683.

He disputed Mr. Coppola's characterization of his adjustment as unorthodox because the weighted-average cost of capital is presented in every corporate finance textbook. In response to Mr. Gorman's testimony that it has not been adopted by state regulatory commissions, he testified that it is used in some other countries and other types of regulatory agencies including the Surface Transportation Board and the Federal Communications Commission. He also testified that the Alabama Public Service Commission recently characterized his focus on the relationship between the market value and the associated financial risk of the utility as "compelling". [420]

Dr. Vilbert also denied that he believes there are two levels of financial risk, testifying that there is only one measure of financial risk, but noting that "the financial risk of a company with 60 percent equity . . . is different from that of a company with 50 percent equity." Further responding to Mr. Gorman, he testified that Mr. Gorman's view of financial risk is really "default risk": "Financial risk is the additional variability of return for equity investors due to the use of debt and other fixed payment sources of financing."[421]

Regarding Mr. Megginson's concern with the complexity of his calculations, Dr. Vilbert testified that the steps to his analysis are clearly laid out in his exhibits, asserting that the analysts were able to follow his calculations.[422] Regarding his objection to Dr. Vilbert's use of the highest debt cost in his analysis, 4.8%, for DTE, Dr. Vilbert testified:

> Mr. Megginson states that my ATWACC calculation "calls for the use of BBB rated debt costs when the proxy group's average cost of debt

---

[420] See 4 Tr 685-686.
[421] See 4 Tr 686.
[422] See 4 Tr 684.

> appears to be BBB+ or higher, and DTE Electric's debt is rated even higher by S&P."78 This claim is misleading for two reasons.
>
> First, my ATWACC calculation appropriately uses estimates of the current market cost of debt based on Bloomberg indices of long term utility bond yields. These indices group bonds in broader "A" and "BBB" bands of S&P credit ratings, such that the "BBB" yields incorporate companies with ratings ranging from BBB- to BBB+. Contrary to Mr. Megginson's claim, my calculation attributes a cost of debt to each individual proxy group company based on whether its credit rating falls into Bloomberg's "A" or "BBB" band.
>
> Second, Mr. Megginson is incorrect that "DTE Electric's debt is rated even higher" than BBB+. His own exhibits acknowledge that DTE Electric's corporate issuer credit rating from S&P is BBB+. Mr. Megginson's comment seems to refer to the Company's senior secured credit rating, which, as discussed at length in Section IV.B above, is not a meaningful indicator of DTE Electric's cost to raise debt capital based on its financial metrics.[423]

f. Discussion

Again, the briefs of the parties generally follow the testimony of their witnesses. There is no doubt that Dr. Vilbert's ATWACC analysis is complex. It requires numerous assumptions including measures of equity ratios, debt, and tax costs. Despite over 100 pages of direct and rebuttal testimony, there are several choices embedded in Dr. Vilbert's analysis that he did not explain. For example, he did not address Mr. Megginson's concern with his choice of 4.8% as the cost of debt to use in backing out the cost of equity for DTE from the average after-tax average weighted cost of capital for his proxy group. He testified in rebuttal:

> [My] ATWACC calculation appropriately uses estimates of the current market cost of debt based on Bloomberg indices of long term utility bond yields. These indices group bonds in broader "A" and "BBB" bands of S&P credit ratings, such that *the "BBB" yields incorporate companies with ratings ranging from BBB- to BBB+.* Contrary to Mr. Megginson's claim, my calculation attributes a cost of debt to each individual proxy group

[423] See 4 Tr 684-685.

> company based on whether its credit rating falls into Bloomberg's "A" or "BBB" band.[424]

This generalized testimony does *not* address Mr. Megginson's concern. Dr. Vilbert claimed his ATWACC method is necessary for greater precision, and he also testified in response to Mr. Megginson's objection that "[s]implicity is not a virtue if it leads to inaccuracy." Thus, it clearly calls for a better explanation why he did not seek a more precise debt-cost estimate. A review of his debt cost estimates also shows that he did not just use two bands, "A" and "BBB- to BBB+", since the debt costs listed in his Schedule B6.11 include values of 4.1%, 4.4%, 4.5%, 4.6%, and 4.8%; the debt costs listed in his Schedule B6.7 include values of 4.1%, 4.4%, and 4.8%. This PFD finds that Dr. Vilbert did not substantiate the reasonableness of the assumptions utilized in his ATWACC analysis, and did not establish that it promotes accuracy.

Another troubling aspect of Dr. Vilbert's model that this discrepancy highlights, however, is that once the average after-tax weighted average cost of capital is determined, using a *higher* cost of debt to back out the required return on equity for a company will produce a *lower* required rate of return. For example, looking at Dr. Vilbert's multistage DCF analysis, if a cost of debt of 4.6% were used instead of the 4.8% that Dr. Vilbert used, the resulting return on equity would be 9.4% instead of 9.3%.

Also, Dr. Vilbert did not directly discuss the different capital structures used in his DCF and CAPM analyses. While he relies on the results of his DCF analysis to support the reasonableness of his ECAPM and scenarios 2 and 3, he does not explain that the greater magnitude of the ATWACC adjustment for the DCF analysis shown by Mr. Gorman at 6 Tr 1932 is attributable to the use of a capital structure with a higher

[424] See 4 Tr 684.

equity ratio (59% compared to 56%), and the exclusion of several low returns from the average, as discussed above.

This PFD finds Mr. Megginson's, Mr. Gorman's, and Mr. Coppola's testimony persuasive that the ATWACC method is unduly complex, resulting in excessive returns on equity, and is inconsistent with the goal of setting a return on equity to provide the appropriate return on the investment in DTE. Instead, it is clear from Dr. Vilbert's rebuttal testimony and a review of his analysis that indeed he does recommend that the otherwise determined cost of equity be increased to reflect the high market-to-book ratios of the proxy companies. As Mr. Coppola and Mr. Gorman testified, this is not appropriate because those high market-to-book value ratios are driven by returns established by regulatory commissions, while DTE does not have publically traded stock with a market value. The bottom line is that the Commission is not obligated to produce a return on equity for DTE that is sufficiently high that it provides the otherwise-indicated return on equity to DTE's parent company's market-value equity ratio. This PFD recommends that the Commission give no weight to the ATWACC calculations presented by Dr. Vilbert.

6. <u>Other Authorized Returns</u>

Several witnesses looked at the rates of return on equity authorized by other regulatory commissions.

a. *Staff*

Mr. Megginson testified that Staff also reviewed the authorized rate of return decisions for electric utilities rendered by other State Commissions across the country for 2015-2016, which he testified was 9.88% as shown in Exhibit S-4, Schedule D-5, page 12. He also noted that the authorized return on equity for the proxy group companies is 10.01%.

b*. Attorney General*

Mr. Coppola testified that since 1990, return on equity rates granted by regulatory commissions have steadily declined from over 12.7% in 1990 to less than 10% in 2014 and 2015. He presented Exhibit AG-35 to show the returns on equity authorized in 2015 and the first quarter of 2016, averaging 9.6%.[425] He also reiterated his concern that regulatory commissions have been slow to embrace lower rates during a prolonged period of low interest rates.

c. ABATE

Mr. Gorman reviewed authorized returns on equity in connection with electric utilities' credit standing and access to capital. He presented a graph showing authorized rates of return steadily declining over the last ten years.[426] He also testified that over the period 2010-2015 the electric utility industry has experienced a number of credit upgrades, presenting a table at 6 Tr 1893 showing both upgrades and downgrades over the period, to show upgrades outpacing downgrades in 2011 and 2013 through 2015. He also quoted Moody's Investor Service from 2015 indicating that in January and February of 2014 ratings of 147 U.S. electric and gas utility ratings were upgraded as part of a sector-wide rating action that reflected a more favorable view of the relative credit supportiveness of U.S. utility regulation. Addressing the utility industry's ability in recent years to support large capital programs, he cited an Edison Electric Institute report indicating that in the ten-year time period from 2005 to 2015

[425] See 6 Tr 1854.
[426] See 6 Tr 1890-1891.

capital expenditures tripled while the majority of funding for these capital expenditures (75%) came from internally-generated funds.[427] He presented Exhibit AB-3 to show that the historical valuation of electric utilities based on price-to-earnings ratios, market price-to-cash ratios, and market price-to-book ratios are strong relative to the last 15 years. To Mr. Gorman: "This robust valuation is an indication that utilities can sell securities at high prices, which is a strong indication that they can access equity capital under reasonable terms and conditions, and at relatively low cost."[428] He recommended that the Commission consider this information in evaluating the appropriate return on equity for DTE.

He took issue with Dr. Vilbert's recommendation as too high, and in rebuttal testimony, also objected to Staff's recommendation as too high, citing the information he had presented regarding returns authorized for other utilities.

d. Walmart

Mr. Tillman expressed concern about the level of DTE's requested return on equity. He presented information regarding rates of return authorized by other commissions in Exhibit GWT-4. He testified that according to data from SNL Financial, the average of the 102 reported electric utility rate case ROE's authorized by state regulatory commissions to investor-owned electric utilities in 2013, 2014, 2015 and to date in 2016 is 9.73%. He testified that the range over that time period is 8.72% to 10.95%, and the median is 9.75%. He testified that the comparable average return for vertically integrated utilities only was an average of 9.8%, and described a declining trend in authorized returns for those utilities from an average of 9.97% in 2013 to 9.75%

---

[427] See 6 Tr 1894.
[428] See 6 Tr 1895.

in 2015, with the information he had for 2016 indicating an average of 9.70%.[429] He also presented a table showing authorized returns in Michigan above national averages from 2013 through the present. [430]

e. Rebuttal

Mr. Gorman took issue with Staff's data regarding the industry average authorized return in 2015 and the first quarter of 2016, contending that Staff's average of 9.84% from Schedule D5 of Exhibit S-4, page 13 was from a 2015 source and could not reflect first-quarter 2016 results. Also, in cross-examination of Mr. Megginson, ABATE presented Exhibit A-30, a discovery response from Staff providing among other information a breakdown of the rates of return that are included in Staff's historical rate of return data.

f*. Discussion*

In its clear from a review of the information presented that rates of return have generally fallen in recent years, while the authorized returns in the compilations presented by the witnesses generally fall within the range of 9.5% to 10%.

7. <u>Discussion of Risk and other Factors</u>

In making their final recommendations, the analysts discussed their perceptions of risk and other factors that led them to that selection.

a. DTE

Looking at his range of results Dr. Vilbert recommended a return on equity for DTE of 10.5%. He testified that DTE has higher risk than the proxy companies. He discussed DTE's lack of a revenue decoupling mechanism, the existence of retail

[429] See 6 Tr 1741-1742.
[430] See 6 Tr 1743.

choice, economic conditions in DTE's service territory including high rates of poverty and the size of the auto industry, DTE's capital requirements, and its nuclear plant ownership as contributing to its business risk. [431]

b. Staff

Mr. Megginson testified that based on the results of Staff's cost of equity models and review of returns authorized by other commissions and the average authorized return on equity for Staff's proxy group, it is Staff's judgment that a cost of equity recommendation for DTE falls within the range of 9.0% to 10.0%.[432] He further testified: "Considering the Company's current authorized ROE of 10.30% and taking into consideration the concept of gradualism, Staff recommends the cost of equity of 10.00% in its overall cost of capital recommendation."[433]

Aside from his disputes with Dr. Vilbert's modeling, as discussed above, Mr. Megginson also took issue with DTE's requested rate of return as outside the range of returns authorized in the current environment, and he took issue with it as inconsistent with the favorable regulatory treatment granted utilities under 2008 PA 286. He also testified that while Staff's recommendation of 10.0% is in line with the proxy group average return on equity, DTE has a higher credit rating than the proxy group average, indicating "DTE Electric is viewed as a safe or even safer investment than the companies in Staff's proxy group."[434]

---

[431] See 4 Tr 602-609.
[432] See 5 Tr 1401.
[433] See 5 Tr 1401-1402.
[434] See 5 Tr 1403.

c. Attorney General

Mr. Coppola reviewed the results of his models as shown in exhibit AG-31 and recommended a return on equity of 9.75%. He testified that giving 50% weight to his DCF results, which he finds the most reliable, and 25% each to the CAPM and risk premium results leads to a return of 9.05%, but he recommends the higher rate of 9.75% for the following reasons:

> First, although the industry peer group return is an appropriate check on the reasonableness of my conclusion, it may not incorporate the unique risks and circumstances that exist with DTE Electric and how investors perceive those risks—in particular, serving a territory that is highly dependent upon the automotive industry. Second, as mentioned above, the extent to which investors anticipate higher interest rates is uncertain. As such, while the cost of common equity under the DCF approach is an accurate assessment of expectations for the forecasted test year, the higher interest rates assumed in this case may very well produce a different result should such higher interest rates become a reality. In this regard, a potential 10% correction in utility stock prices due to higher interest rates would produce a 0.40% increase in the cost of capital under the DCF approach. [435]

He also testified that this approach represents gradualism.[436]

d. ABATE

Mr. Gorman recommended that the Commission adopt a return on equity of 9.2% as the midpoint of his range of 8.8% to 9.6%. He testified that his return on equity estimates reflect observable market evidence, the impact on Federal Reserve policies on current and expected long-term capital market costs, an assessment of the current risk premium built into current market securities, a general assessment of the current investment risk characteristics of the electric utility industry, and the market's demand for utility securities. He also testified that DTE is comparable to his proxy group:

---

[435] See 6 Tr 1855-1856.
[436] See 6 Tr 1855-1866.

The proxy group is shown in Exhibit AB-4. The proxy group has an average corporate credit rating from S&P of BBB+, which is identical to S&P's corporate credit rating for DTE Electric. The proxy group has an average corporate credit rating from Moody's of Baa1, which is two notches lower than DTE Electric's corporate credit rating from Moody's of A2. Based on this information, I believe my proxy group is reasonably comparable in investment risk to DTE Electric. The proxy group has an average common equity ratio of 47.4% (including short-term debt) from SNL Financial ("SNL") and 49.8% (excluding short-term debt) from The Value Line Investment Survey ("Value Line") in 2015. DTE Electric's requested ratio of 50.0% common equity to total permanent capital is in line with that of my proxy group.

Based on these risk factors, I conclude the proxy group reasonably approximates the investment risk of DTE Electric. [437]

Mr. Gorman also looked at various financial metrics to conclude that at his recommended return on equity of 9.2%, DTE's financial credit metrics would still support an investment-grade bond rating.[438]

e. Rebuttal

In his rebuttal testimony, Dr. Vilbert took issue with any reliance on credit agency reports or credit ratings as an indication of risk.[439] He testified:

[T]he goal of the credit rating agencies is not to measure the systematic risk of a company's equity, but rather to evaluate the probability that a company will default on its debt. Default is a manifestation of extreme financial distress, wherein the company cannot make good on its debt obligations. For financially healthy companies, such as DTE Electric and the companies in the electric sample, the probability of default is generally quite low. This is reflected in the fact that they all receive credit ratings at or above BBB-, which is the standard threshold for "investment grade" debt. I use an investment grade credit rating as a sample selection criterion to remove companies possibly suffering from financial distress, but credit ratings play no role in the estimation of the cost of equity.

Unlike credit ratings, equity risk has to do with the systematic risk measured by the beta coefficient, or the tendency of a security's returns to respond to returns in the stock market. For this reason, a higher credit rating does not necessarily correspond to lower systematic risk.

[437] See 6 Tr 1899-1900.
[438] 6 Tr 1930.
[439] See 4 Tr 675.

> Conversely, two companies with identical credit ratings need not have the same required return on equity. For instance, factors that make a company's cash flows more sensitive to the broader market would affect the cost of equity even if they do not affect the individual company's probability of default enough to warrant a change in credit rating.[440]

Dr. Vilbert referenced his direct testimony for an explanation of why he believes DTE is riskier than his proxy group.

f*. Discussion*

Again the parties' briefs generally track the testimony of their witnesses. The Commission has recognized the importance of careful selection of a proxy group and the use of credit ratings in that selection. In its November 4, 2010 order in Case No. U-16191 at page 28 the Commission explained:

> The Commission is persuaded that the Staff's analysis appropriately reflects Consumers' risk environment and required rate of return. The Staff's proxy group had an average S&P bond rating of BBB+ and an average Moody's bond rating of A3. These credit ratings are identical to that of Consumers and consider a multitude of financial and business risk factors including the effect of the local, state, and national economic conditions, utility service territory, regulatory environment, cash flow adequacy, liquidity, peer comparison, and competitive position, among many others. Accordingly, the Commission finds that the Staff's analysis is the most reasonable and reflective of the company's financial position.[441]

On this record, this PFD finds that by any objective measure, DTE is no riskier than the proxy group averages. While DTE has identified certain risks and challenges facing the company, it has not compared these in any systematic way to the risks facing other companies in the proxy group. While many of the concerns raised by Dr. Vilbert are directed to whether DTE's rates will continue to be adequate, this PFD notes that DTE faces little regulatory lag, having self-implemented rates in this case one month after the

[440] See 4 Tr 675.
[441] Also see October 20, 2011 order in Case No. U-16472, pages 39-40.

projected test year ended from its last rate case, and has also expressed confidence in its revenue forecasting that is used in ratemaking.

8. Recommendations

Reviewing the different analyses presented by the witnesses, it has long been recognized that there is no precise mathematical formula to determine the appropriate return on equity. Citing *Bluefield* and *Hope*, supra, the Commission has explained:

> The Supreme Court has made clear that, in establishing a fair ROR, consideration should be given to both investors and customers. The ROR should not be so high as to place an unnecessary burden on ratepayers, yet should be high enough to ensure investor confidence in the financial soundness of the enterprise. Nevertheless, the determination of what is fair or reasonable, "is not subject to mathematical computation with scientific exactitude but depends upon a comprehensive examination of all factors involved, having in mind the objective sought to be attained in its use." *Meridian Twp v City of East Lansing*, 342 Mich 734, 749; 71 NW2d 234 (1955).[442]

Based on the discussion and findings above, this PFD finds that Staff's analysis is objectively reasonable and consistent with past Commission decisions and its recommended rate of return is reasonable, consistent with the requirements of Bluefield and Hope, and should be adopted. DTE's requested return on equity is premised on flawed modeling and unjustified assumptions and is outside the range of reasonableness for DTE. This PFD recognizes that the models produce results which are generally below the 10% rate of return this PFD recommends, but Staff's recommendation also considers principles of gradualism that the Commission has found important, as well as the utility's continuing need for capital.

[442] See October 20, 2011 order, Case Nos. U-16472, U-16489, page 30.

D. Overall Rate of Return (Summary)

Based on the foregoing discussion, this PFD recommends that the Commission adopt a 50/50 capital structure with a long-term debt cost of 4.61%, a short-term debt cost of 1.58%, and a return on equity of 10%, resulting in an estimated overall weighted after-tax cost of capital of 5.52%% as shown in Exhibit S-4, Schedule D1.

VII.

ADJUSTED NET OPERATING INCOME

Net operating income (NOI) constitutes the difference between a company's operating revenue and its operating expenses including depreciation, taxes, and allowance for funds used during construction (AFUDC). Adjusted NOI includes the ratemaking adjustments to the recorded NOI test year for projections and disallowances.

A. Sales Forecast and Revenue (Exhibit A-10, Schedule C5, line 4)

DTE's projected test year revenue forecast was based on Mr. Leuker's sales forecast, which is presented separately by class, with and without choice customers, in his Exhibit A-12. Because DTE filed its case before the Commission's last rate order in Case No. U-17767, it did not fully capture the revenue increase authorized in that case, as discussed in section 1 below. Additionally, Staff took issue with DTE's sales forecast for Residential Income Assistance (RIA) customers, as discussed in section 2, and the Attorney General took issue with DTE's residential sales forecast, as discussed in section 3.

1. Adjustment for February 23, 2016 order in Case No. U-17767

In its brief, DTE adjusted its projected revenue at present rates to reflect the additional rate relief provided in the Commission's February 23, 2016 order on rehearing in Case No. U-17767, allowing amortization of then-estimated COL expenses. Because DTE's rate filing was made on February 1, 2016, before the Commission issued that order, DTE's projected revenue at present rates did not reflect this adjustment. Mr. Stanczak did use the revised rates in his self-implementation exhibits.[443] DTE's adjustment increased the revenue at present rates by $4.5 million.[444] No party challenged this adjustment.

2. Staff Adjustment to RIA Sales

As Staff explains in its brief, Staff's net operating income calculation increased projected revenue by $720,000 to reflect Ms. Rivera's analysis of the likely number of Residential Income Assistance (RIA) customers.[445] In her analysis, Ms. Rivera looked at the historical levels of participation in the RIA program and considered the availability of the Rate D1.6 adopted in Case No. U-17767. She recommended a revenue projection based on 35,000 customers, rather than DTE's estimate of 45,000 customers.

DTE did not provide rebuttal testimony addressing this projection. It acknowledges Staff's projection in its reply brief, indicating there appears to be no disagreement.[446] This PFD finds on the basis of this record that Staff's minor revenue adjustment is reasonable and should be adopted.

[443] See 2 Tr 34-35.
[444] See DTE brief, page 10.
[445] See Staff brief, pages 47-48.
[446] See DTE reply brief, page 118.

3. Residential Sales Forecast, Use per Customer

Mr. Coppola reviewed the sales forecasts underlying DTE's revenue projections. He took issue with the residential sales forecast based on his conclusion that this forecast understates usage per customer.[447] Using more recent data obtained from DTE, Mr. Coppola presented Exhibit AG-1 to show historical changes in residential use per customer in comparison to DTE's projections. He also calculated a $14.2 million reduction to the revenue requirement from adjusting the residential sales forecast, as shown in Exhibit AG-2. The Attorney General argues that the Commission should adopt Mr. Coppola's adjustment.

Mr. Leuker presented rebuttal testimony on this topic and was cross-examined by the Attorney General. He testified that Mr. Coppola understated 2015 residential sales and did not reduce 2016 first-quarter residential sales to account for the leap-year day. He presented Exhibit A-26 to reflect a revision of Exhibit AG-1 and to compare first-quarter 2015 and 2016 data. He also reviewed the basis for DTE's residential sales forecast characterizing it as a "detailed, appliance-by-appliance method" that relies on biannual saturation surveys for appliance usage.[448] On cross-examination, he also testified that the "end use" model DTE uses in its modeling for residential sales does not use any liner regression.[449] He further explained that the biannual surveys reflect approximately 3,600 responses received out of 15,000 surveys sent out and cover 39 appliances. Mr. Leuker also testified that DTE is "very confident" in its modeling:

> [W]e constantly check the accuracy of the model in past years. And on average, on average the residential forecasts, when we look at year

[447] See 6 Tr 1779-1782.
[448] See 4 Tr 756-758.
[449] See 4 Tr 767.

> ahead kind of forecast accuracy, it's around 99 percent in the residential class.[450]

In its brief, DTE cites Mr. Leuker's rebuttal testimony and argues there is no reasonable basis to conclude anything other than that DTE Electric's sales are declining as projected by Mr. Leuker.[451]

In his brief, the Attorney General addressed Mr. Leuker's rebuttal testimony, arguing that the adjustments Mr. Leuker presented to Mr. Coppola's 2015 and year-ending-June-2016 sales figures cancel each other out.[452] The Attorney General also argues:

> On cross examination, Mr. Leuker admitted that he does not use historical numbers to determine his residential forecast and does not use a regression model of any kind, but only uses the 39 different appliance survey. (Tr 767-770.) In fact, Mr. Leuker states in his rebuttal that using historical data to determine the forecast is not reliable since it goes up and down from year to year and ignores changes such as the enacted energy efficiency standards. (Tr 757.) Yet, Mr. Lueker states in his direct testimony that the "accepted industry standard for electricity forecasting" is using a regression that begins with the "assembly of historical data." (Tr 739-740.) In addition, Mr. Leuker admitted that "the historical average customer usage already reflects the increase in the appliance efficiency standards that has taken place." (Tr 777.)[453]

DTE responded to the Attorney General's analysis of the 2015 data as follows:

> The AG attempts to support Mr. Coppola's flawed analysis, asserting without support or explanation that "Mr. Leuker's adjustments simply cancel each other out and do not undermine Mr. Coppola's higher residential sales forecast using the historical and current numbers" (AG Initial Brief, p 11). As indicated above, both of Mr. Coppola' errors masked the reality of declining residential sales, and these errors were cumulative so they plainly did not "simply cancel each other out."[454]

---

[450] See 4 Tr 772-773.
[451] See DTE brief, pages 32-34.
[452] See Attorney General brief, page 11.
[453] See Attorney General brief, page 11.
[454] See DTE reply brief, page 23-24.

This is a difficult issue to resolve. DTE did not present a detailed basis for its forecast in its direct case and the details of its forecasting model for residential usage are understandable principally as a result of Mr. Coppola's analysis and the Attorney General's cross-examination of Mr. Leuker. While Mr. Leuker did explain that DTE used an "end use" model in his direct testimony, it is not apparent from a review of that testimony that no regression analysis is involved and that historical data is only used occasionally as a check on the forecast.

Nonetheless, the 2015 and 2016 customer usage data are roughly consistent with DTE's forecast. As Mr. Leuker testified in rebuttal, the proper temperature-normalized usage for 2015 is 15,054 Gwh. If Mr. Coppola's Exhibit AG-2 were corrected to reflect this value, the adjustment to the revenue requirement calculated in that exhibit would be only approximately $11.7 million.

The 2015 usage is approximately 0.5% higher than DTE's forecast for 2015 as presented in Exhibit A-12, Schedule E1. Including the new information in the helpful format used by Mr. Coppola, the 0.5% increase above forecast levels would turn the -1.2% shown in column d of that exhibit to a value of -0.9%, a smaller decrease over 2014 values, and would change the five-year compound annual growth rate from -0.3% to -0.2%. And, as shown in Exhibit A-26, the revised 2015 value updates the three-year compound growth rate from -0.6% for the years 2011-2014 to -0.5% for the years 2012-2015. While these revised rates tend to indicate DTE's test year projection will be overstated, the 0.5% error rate is consistent with Mr. Leuker's testimony that the company's forecast has an average error rate of 1% over a one-year period. In addition, the preliminary 2016 data, which are available only for the first four months of the year, show a significant decrease in consumption per customer in comparison to the comparable months of 2015.[455]

On this basis, and based on Mr. Leuker's testimony regarding the detailed analysis underlying his projections and their degree of accuracy, this PFD recommends that the Commission accept DTE's projection for the purposes of this case. Nonetheless, the Commission should direct DTE to provide more information in its next rate case to both explain the basis for its projection and to support the accuracy of that projection.

B. Fuel & Purchased Power Expense (see Exhibit A-10, Schedule C5, line 5)

DTE's projected fuel and purchased power expense is shown in Exhibit A-10, Schedule C5, line 5. There is no dispute among the parties. Mr. Nichols incorporated the same value in Staff's analysis, as shown in Exhibit S-3, Schedule C1, line 3.

C. O&M Expenses

Ms. Uzenski presented DTE's overall O&M expense projections with a categorization of expenses in Exhibit A-9, Schedule C5. She also presented Schedule C1.1, which shows the projected increase in O&M expenses of $149.2 million from 2014 to the projected test year, due primarily to inflation, higher benefit costs, nuclear refueling and maintenance projects, tree trimming, and environmental costs. She testified that these increases are partially offset by AMI savings, plant retirement impacts, lower average restoration costs and uncollectibles expense, and reduced incentives expense.[456]

---

[455] See Exhibit A-26, page 2.
[456] See 4 Tr 814.

Staff recommends a total reduction of $69.3 million in projected O&M expense as shown in Exhibit S-3, Schedule C1.1. The Attorney General recommends a total expense reduction of $132.3 million as shown in Exhibit AG-4. Kroger recommends a reduction of $38 million to eliminate non-labor O&M expense projections. In the discussion that follows, the general arguments advanced by the parties regarding the use of an inflation factor to project test year O&M expenses are reviewed in section 1, followed by a review of arguments related to each of the line items of Exhibit A-10, Schedule C5.

1. Inflation

DTE's O&M expense projections generally rely on an inflation projection. Ms. Uzenski calculated the inflation factors DTE used for most of its O&M expense projections. She testified that she calculated a composite rate based on a labor factor of 3% that she obtained from Mr. Wuepper, and a non-labor factor based on the CPI-Urban obtained from Mr. Leuker. She testified that the labor inflation rate reflects that DTE's labor costs are driven by "contracts or market based pay practices, and thus are not tied to CPI," and that she used the same rate for contract labor.[457]

There is substantial disagreement among several of the parties regarding the use of inflation in O&M expense projections. Staff and the Attorney General expressly object to DTE's use of a "blended" rate incorporating a CPI inflation projection and DTE's projected internal labor cost increase. Mr. Megginson recommended inflation rates based on forecast data from Value Line, Global Insight, and the Energy Information Administration, which Staff used in its analysis.[458] In its brief, Staff argues

[457] See 4 Tr 813814; Exhibit A-10, Schedule C5.15.
[458] See 5 Tr 1389 , Exhibit S-4, Schedule D3, page 2.

that Staff's inflation rate was based on the most current projections consistent with past rate cases. Staff argues that DTE's use of a rate of inflation that blends a traditional inflation estimate with internal wage rate projections has not been adopted before.[459]

Mr. Coppola explained the Attorney General's objections to DTE's blended inflation rate:

> Approximately $78.2 million of this amount represents increases calculated by the Company based on inflation factors which in most cases is based upon a blend of the Consumer Price Index ("CPI") and 3% forecasted annual wage increases for union and non-union employees. Use of such a "blended rate" has not been requested before by the Company (or approved by the Commission) in any past general rate case in recent years to my knowledge.[460]

Kroger and the Attorney General object to the use of an inflation factor at all for non-labor O&M expenses. Mr. Coppola recommended that the Commission remove all inflation from test year O&M expense projections except for a $3.5 million inflationary increase for employee health care projections:

> More importantly, and contradicting some of the testimony in this case, the Company has not experienced across the board inflation pressure on its operating costs and in fact the Company has been able to hold O&M costs flat for about the past 5 years. Exhibit AG-11 includes a discovery response from the Company confirming this fact.
>
> According to a response to a Staff Audit Request in Case No. U-17767, the Company stated that in 2013 it launched the Competitive and Affordable Rate Strategy (CARS) in an effort to lower its cost structure to dampen potential rate increases due to capital additions thereby keeping overall rates as low as possible. This strategy was implemented in 2014 and will continue through 2018. Although these cost reduction goals are aspirational in nature it seems clear that the Company has been able to achieve them to a large degree, thus offsetting any inflationary cost increases and keeping O&M expenses nearly flat during the past five years.[461]

[459] See Staff brief, pages 50-51.
[460] See 6 Tr 1786-1787.
[461] See 6 Tr 1787.

Ms. Uzenski testified in rebuttal:

> Witness Coppola points to a discovery response (in reference to Company Witness Mr. Stanczak's direct testimony, page 8) that states the Company has been able to hold O&M flat for about the past five years. He concludes that since the Company has been able to hold costs down in the past, the Company must be able to do the same in the future. Witness Coppola's assertion does not comport with the facts because prior year cost reductions that helped offset inflation and wage increases, were significantly influenced by benefit plan design changes that reduced the Company's Other Post- Employment Benefits (OPEB) liability which created a temporary large reduction in the OPEB expense accrual related to the amortization component. This can be seen on Company Witness Mr. Wuepper's Exhibit A-10, Schedule C5.11, line 9. Column (c) reflects a $68.8 million increase in expense from the historical to the projected period. Thus, this item is no longer available to offset continuing wage increases and non-labor inflation. In addition, both the Staff and the Company provided inflation data based on objective indices in direct testimony. An assumption of zero inflation in the projected period is unreasonable and unsupported and should be rejected by the Commission.[462]

In its reply brief, DTE cites Ms. Uzenkski's testimony arguing that prior cost reductions were significantly influenced by benefit design changes for retirees, which were amortized through the end of 2016. DTE also argues that Mr. Coppola's proposal is not based on data or evidence.[463]

Kroger witness Mr. Townsend objected to the use of an inflation factor for non-labor O&M:

> From a ratemaking perspective, I have two serious concerns with DTE's inclusion of inflation in its forecasted test period revenue requirement. First, at a broad policy level, I have concerns about regulatory pricing formulations that reinforce inflation. This occurs when *projections* of inflation are built into formulas that are used to set administratively-determined prices, such as utility rates. Such pricing mechanisms help to make inflation a self-fulfilling prophecy. As a matter of public policy, this is a serious concern. It is one thing to adjust for inflation after the fact; it is another to help guarantee it. For this reason, I believe that regulators

[462] See 4 Tr 853-854.
[463] See DTE reply brief, page 40.

should use extreme caution before approving prices that guarantee inflation before it occurs.

* * *

A related, but distinct, concern involves the building of this "cost cushion" into the Company's test period costs. Allowing this type of systemic uplift in rates goes well beyond the basic rationale advanced by advocates for using a projected test period, which is to ameliorate the effect of regulatory lag on the recovery of investment in new plant.

* * *

The best evidence of what it costs DTE for non-labor O&M is the Company's actual costs recorded in the historical period, adjusted for certain known and measurable changes. The cost increases represented by DTE's inflation assumption may or may not come to fruition. In any case, DTE should be expected to strive to improve its O&M efficiency on a continuous basis, and thereby lessen the net impact of inflation on its O&M costs. It is not reasonable to simply gross up the Company's historical period costs by an inflation factor and pass these costs on to customers.[464]

As shown in Exhibit KC-1, Mr. Townsend recommended excluding $38 million for non-labor O&M.

Mr. Leuker, whose direct testimony contained a discussion of the economic outlook underlying DTE's sales forecasts, also provided rebuttal testimony explaining that inflation is "real":

The federal government tracks inflation and reports 1 it monthly. Various inflation indices are used throughout the business world to determine costs and prices. Even Witness Townsend admits in his testimony on page 6, line 20 through page 7, line 2 that inflation exists by citing the Federal Open Market Committee's (the Fed's) expectation for core personal consumption expenditures (PCE) inflation and the Congressional Budget Office's (CBO's) forecast of core inflation.[465]

In its reply brief, DTE also addresses Kroger's argument. DTE argues that Kroger's brief acknowledges that inflation exists and will continue to exist. DTE argues that

---

[464] See 3 Tr 54-56.
[465] See 4 Tr 759.

inflationary pressures on costs must be recognized for rates to be set prospectively "at a level that allows the utility to provide service and its customers to receive service based on the estimated costs of providing service."[466]

While to some extent each cost category should be evaluated on the basis of specific evidence regarding that cost category, the Attorney General and Kroger raise a valid general concern that inflationary increases may be excessive or become a self-fulfilling prophecy. The Commission has considered productivity offsets to inflationary pressures in setting rates in some cases. For example, in Case No. U-10755, the Commission explained:

> Using an escalation rate of ½ of inflation is reasonable in this case because it is recognized that Consumers' obligation to contain costs prudently and strikes an appropriate balance between inflationary pressures and expected increases in productivity and efficiency.[467]

Staff and the Attorney General are also correct that DTE did not justify its non-standard use of its own internal labor rate to increase the inflation estimates for the projected test year. Productivity increases are generally associated with improvements in operating efficiency attributable to capital expenditures such as new facilities and new software, as well as with increased labor costs. Thus, in Case No. U-14547, the Commission explained:

> The Commission agrees with the ALJ and Staff that some O&M expenses will likely increase at a higher rate than inflation, and others will increase at a lower rate, or may even decrease due to productivity increases or cost reductions. Thus, considering the offsetting effects of lower than average increases for some O&M expense components and productivity increases, there is no need to provide additional revenue for every component of O&M that is expected to increase at a higher than average rate.[468]

---

[466] See DTE reply brief, page 25.
[467] See March 11, 1996 order in Case No. U-10755, page 50
[468] See November 21, 2006 order in Case No. U-14547, page 47.

Considering these arguments in addressing each of the disputed categories discussed below, this PFD generally recommends that the Commission adopt Staff's traditional inflation factors while also considering any additional specific information pertinent to that cost category relating to alternative cost or savings estimates.

2. <u>Steam Power Generation (Exhibit A-10, Schedule C5, line 1)</u>

Mr. Warren presented DTE's projected steam power generation O&M expense projection based on 2014 historical test year expenses adjusted for inflation and "known and measureable changes", as shown in his Schedule C5.1 of Exhibit A-10.[469] His O&M expense exhibit reflects the requested transfer of "non-generation fuel" from base rates to PSCR costs, discussed in more detail below. Ms. Uzenski also testified that she directed him to include amortization expense for obsolete inventory, which is discussed below. Staff and the Attorney General recommended adjustments to this category.

a. Staff.

Ms. Shi presented Staff's recommendations for this category. Ms. Shi recommended two adjustments to projected expenses for steam power generation: 1) a reduction of $10.7 million to reflect Staff's inflation factors, and 2) the removal of $8,003,000 due to the pending retirement of River Rouge Unit 2. These adjustments are reflected in Exhibit S-8.0 and S-8.1. Regarding inflation, she testified that Staff used the inflation factors of 0.09%, 1.45 %, and 2.7 % as supported by Mr. Megginson. DTE did not object to Staff's inflation factors for the non-labor portion O&M, but restated

[469] See 3 Tr 141-146.

DTE's weighted average to blend these numbers with DTE's labor rate weightings and numbers.[470]

Ms. Shi's second adjustment removed projected O&M expenses for River Rouge Unit 2, which total $8,003,000 as shown in Exhibit S-8.2, page 2.[471] As explained above, DTE announced the retirement of River Rouge Unit 2 after it filed its rate application. DTE acknowledged that this adjustment should be made in its initial brief.[472]

b*. Attorney General*

As discussed above, the Attorney General recommended that no inflationary adjustment be made to this category of expenses. The result would be a $30 million reduction in projected O&M expenses. The Attorney General also recommended that the Commission exclude 50% of the company's requested $3 million additional expense allowance for analysis related to the federal Clean Power Plan, other environmental requirements, and additional integrated resource planning.[473]

Ms. Dimitry testified in support of the company's request to include $3 million in O&M expense to evaluate implementation of the Clean Power Plan and to expand integrated resource planning activities.[474] Mr. Coppola identified the U.S. Supreme Court's stay of the implementation of the Clean Power Plan and DTE's lack of an explicit budget as the basis for his proposed $1.5 million reduction. In its briefs, DTE

---

[470] See DTE reply brief, pages 25-26, arguing that the impact is negligible and citing Ms. Uzenksi's testimony at 4 Tr 813, and Exhibit A-10, Schedule C-5.15.
[471] See 5 Tr 1548.
[472] See DTE initial brief, page 10.
[473] See 6 Tr 1789.
[474] See 3 Tr 235-237.

argues that the projected expenses are appropriate, although it does not discuss Mr. Coppola's testimony. [475]

c. Recommendation

For the reasons discussed above, this PFD recommends that the Commission adopt Staff's inflation factors, unblended, rather than DTE's inflation factors or the Attorney General's recommendation to use no inflation. Staff's adjustment for River Rouge Unit 2 should be adopted. And finally, this PFD recommends that the Commission provide the requested $3 million funding for environmental and planning analyses, on the basis that high-quality analysis is critical to responsible and timely decision-making, including integrated resource planning.

3. <u>Fuel Supply & MERC Fuel Handling (Exhibit A-10, Schedule C5, line 2)</u>

Mr. Milo presented testimony for DTE in support of its projected O&M expenses for fuel supply & MERC fuel handling. As explained by Ms. Shi and as discussed above, Staff recommended an adjustment to DTE's inflation estimate for this category as shown in Exhibit S-8.1 based on Staff's inflation factors. The resulting adjustment is a reduction of $409,000 to DTE's test year projection. Mr. Coppola's recommendation to exclude all inflation includes a $745,000 adjustment to this category, as shown in Exhibit AG-5.

DTE acknowledges the dispute in its reply brief referencing only its general discussion of inflation.[476] For the reasons discussed above, this PFD recommends that the Commission adopt Staff's recommended inflation adjustment.

---

[475] See, e.g., DTE reply brief, page 92.
[476] See DTE reply brief 54-55.

4. Nuclear Power Generation. (Exhibit A-10, Schedule C5, line 3)

Both Staff and the Attorney General recommended adjustments to the rate of inflation used to project this category of expense, discussed in section a below, and Staff also recommended an adjustment of $14,287,000 to normalize projected Program Evaluation and Review Committee (PERC) project spending, discussed in section b.

a. Inflation

Ms. Shi recommended an inflation adjustment of $4.975 million, as computed in Exhibit S-8.1, while the Attorney General recommended excluding all inflation, $9.1 million as shown in Exhibit AG-5. For the reasons discussed above, Staff's inflation adjustment is reasonable and should be adopted.

b. PERC

Regarding the Program Evaluation and Review Committee (PERC) projects, Ms. Shi explained that DTE added $19.2 million to its inflation-adjusted 2014 expense level for nuclear power generation for PERC projects that Mr. Colonnello described as "several large, infrequently performed inspections and unique projects that had not been accounted for in the historic test year."[477] She also explained that DTE had provided information in response to an audit request showing how frequently each of the projects was expected to be performed, presented in Exhibit S-8.4. She testified that Staff determined the project expenses should be normalized based on the next time the project is expected to occur, or over a ten-year period if it is not expected to recur. She presented Staff's calculation of this normalized expense in her Exhibit S-8.3, and

[477] See 5 Tr 1261, 1549.

recommended the resulting $14.287 million adjustment to projected test year O&M expenses for this category.[478]

In rebuttal, Mr. Colonnello testified that although the specific projects will not recur each year, expenditures for PERC projects are typical. He testified that DTE spent $17.6 million more in 2015 than in 2014 and expects to spend $14.8 million in 2016 and 2018.[479] Ms. Uzenski also disagreed with Staff's approach, citing Mr. Colonnello's rebuttal testimony, and proposing an alternative:

> If the Commission adopts Staff's proposal to include only $4.9 million in the revenue requirement, I recommend that the difference between the actual costs incurred for PERC projects in a single year and $4.9 million, be deferred on the balance sheet to account 182.3, Other Regulatory Assets. Years in which costs are below $4.9 million (or zero) will result in a reduction of the regulatory asset via a charge to account 524, Miscellaneous Nuclear Power Expense. Carrying charges at the Company's short-term debt rate should be applied to the monthly balance in the regulatory asset account. If a balance (positive or negative) remains in the regulatory asset account as of the projected test period in a subsequent general rate case, the balance should be included for recovery in that case.[480]

In its brief, DTE relies on this testimony.[481]

In its brief, Staff agrees that deferral of the expenses as outlined by Ms. Uzenski is reasonable with certain clarifications. Staff proposes:

> Any balance (positive or negative) in the PERC regulatory asset, inclusive of carrying costs, as of the beginning of the projected test period in the next DTE Electric rate case subsequent to U-18014, should be amortized to account 524, "Miscellaneous Nuclear Power Expense," over a five year period, beginning in the first month of the projected test period. The annual amortization expense will be included in the revenue requirement within O&M, and the projected unamortized balance of the regulatory asset will be included in working capital.[482]

---

[478] See 5 Tr 1549.
[479] See 5 Tr 1271-1272.
[480] See 4 Tr 857-858.
[481] See DTE brief, pages 44-45.
[482] See Staff brief, page 55.

In its reply brief, DTE states that it agrees with Staff's clarification to Ms. Uzenski's alternative proposal, but also states that it does not believe the expenses should be normalized in the first place.[483]

This PFD finds that Staff's recommendation to normalize the expenses is a reasonable response to critical expenses that are expected to vary significantly from year to year, while protecting DTE's interests in funding for ongoing expenses through the accounting procedures described by Ms. Uzenski and further clarified by Staff in its brief. This PFD finds that ratemaking and accounting treatment provided for in this compromise should be adopted.

5. Hydraulic Power Generation (Exhibit A-10, Schedule C5, line 4)

As explained by Ms. Shi and discussed above, Staff recommended an adjustment to the inflation projection for this category of expense that would reduce DTE's projection by $341,000 as computed in Exhibit S-8.1. Mr. Coppola's corresponding adjustment, removing all inflation, would be $1.5 million for hydraulic and other power generation combined, as shown in Exhibit AG-5. For the reasons discussed above, Staff's adjustment is reasonable and should be adopted.

6. Other Power Generation (Exhibit A-10, Schedule C5, line 5)

As explained by Ms. Shi and discussed above, Staff recommended an adjustment to the inflation projection for this category of expense that would reduce DTE's projection by $466,000. Mr. Coppola's $1.5 million adjustment for this and the hydraulic power generation category is also noted above. For the reasons discussed above, Staff's adjustment is reasonable and should be adopted.

[483] See DTE reply brief, pages 24-35.

7. Distribution System (Exhibit A-10, Schedule C5, line 6)

Mr. Whitman presented testimony in support of DTE's projected electric distribution system O&M expense projection of $307,993,000, including an $893,000 amortization of the proposed regulatory asset for 2014/2015 EVMP expenses of $26.8 million that DTE has withdrawn, as discussed above. Also, as discussed above, DTE proposed that a regulatory asset be created for future ETTP expenditures with each vintage calendar year spending amortized over the subsequent 15-year period. Thus, DTE's projected test year O&M expenses do not include any of the projected 2017 ETTP spending.[484]

Mr. Whitman explained the adjustments DTE made to 2014 expenditures to project the test year expense request. He identified normalizing adjustments including an adjustment for restoration expenses and an adjustment for a change in restoration capitalization as well as expenses associated with the PLD system that are recovered through a separate reconciliation.[485]

The principal dispute among the parties is the expense allowance that should be included in the projected test year for DTE's tree trimming activities. Mr. Whitman testified that in 2015 DTE trimmed a total of less than 4,000 miles with approximately 3100 miles trimmed to the standard specifications and approximately 875 miles using the new enhanced standard as shown in Schedule M5 of Exhibit A-21.[486] He explained why DTE's tree trimming fell below its initial targets:

> 1. Capital trimming work was paused during the first quarter for approximately three months to address customer concerns regarding the Company's new approach to tree trimming. Several process changes

[484] See Uzenski, 4 Tr 841.
[485] See 3 Tr 348.
[486] See 3 Tr 315.

> were made during this time to ensure that customers have greater transparency into (and understanding of the reasons underlying) the scope of work to be completed on their property and to provide a greater degree of customer acceptance. For example, based on customer feedback, the Company changed its approach to now include tree trim debris removal. Debris removal represents a major increase in work scope and greatly influenced cost and production in 2015.
>
> 2. By first addressing the circuits with the highest tree caused customer minutes of interruption, the Company encountered higher tree densities than the system average requiring more time to complete.
>
> 3. The change in scope driven by actual field conditions resulted in a shortage of qualified line clearance tree trimmers. The Company addressed this issue by bringing in qualified line clearance tree crews from out of state. This countermeasure required several months to implement fully as available out-of-state crews were identified. The primary long-term countermeasure to achieve an adequate qualified local workforce is a new line clearance training program jointly sponsored by the Company, tree trimming contractors and IBEW Local 17.[487]

He then explained the improvements the company has implemented, discussing software that is being used to manage workflow, other planning improvements, revised customer communication materials and approach, and efforts to prevent company personnel from removing trees from a customer's property without that customer's knowledge.[488]

He provided two charts showing the company's plans for tree trimming for 2016 and 2017 broken down by distribution system line type,[489] and a schedule showing its plans through 2021, with cost estimates including inflation as well as "work complexity" and "circuit mix".[490] Mr. Whitman also presented numerous calculations of the potential benefits to customers from reduced outage times, relying on a study by the Ernest Orlando Lawrence Berkeley National Laboratory.

[487] See 3 Tr 315-316.
[488] See 3 Tr 316-317.
[489] See 3 Tr 305-306.
[490] See 3 Tr 302.

Mr. Derkos recommended that the Commission base its distribution O&M expense allowance on the most recent five-year average of DTE's actual spending, adjusted for inflation, with an additional increase to reflect an increased tree trimming allowance and to incorporate DTE's requested preventive maintenance expense projection. He also included an offsetting $2.5 million service restoration cost savings estimate. He testified that DTE's 2014 and 2015 distribution system O&M expenditures as reported to FERC showed a significant drop from previous levels, and explained that Staff believes DTE should demonstrate a consistent year-to-year level of increasing spending before a significant increase is granted.[491] Recognizing the lower 2014 and 2015 expense levels, Mr. Derkos testified that the five-year average of distribution O&M expenditures is a more reasonable starting point, presenting Exhibit S-9.0 to show the historical expenditures. Mr. Derkos explained that in computing the five-year average, he adjusted each year for inflation to 2015 dollars, as also shown on Exhibit S-9.0. He testified that he adjusted the line items for inflation through the projected test year using Staff's inflation factors for 2016 and 2017, and made further adjustments for additional tree trimming, outage restoration savings, and preventive maintenance.[492]

Mr. Derkos explained that Staff's adjustment for tree trimming used DTE's target miles for tree trimming in 2016 and 2017, multiplied by DTE's 2015 per-mile tree trimming cost, as shown at 3 Tr 302, inflated for the projected test year. Staff also added an allowance for "trouble tree" trim expense, adjusted for inflation. The result shown in Exhibit S-9.1 is a tree-trimming expense allowance of $75,175,000.[493]

[491] See 5 Tr 1460-1461.
[492] See 5 Tr 1462.
[493] See 5
Tr 1462-1463.

Mr. Derkos testified that he applied this adjustment to FERC account 593 for the maintenance of overhead lines, which he had already adjusted for inflation. He testified that inflating the tree trimming allowance and inflating the total account 593 would be effectively inflating tree-trimming twice, so he subtracted the incremental inflation, which he calculated as $1,836,000. From these calculations, he derived an incremental adjustment of $11,539,000 that Staff recommends as an increase to the inflated historical expense level. He testified that Staff recognizes that DTE will need to spend more than it did in 2015 if it is going to trim more miles than it trimmed that year.

In addition to the $11,539,000 adjustment, Mr. Derkos recommended two additional adjustments to increase the distribution expense allowance: increases of $4.9 million and $1.7 million for preventive maintenance of station equipment and underground lines, respectively. Mr. Derkos also described Staff's $2.5 million offsetting reduction to the overhead line maintenance expense category as a conservative estimate of savings attributable to the increased maintenance effort. He testified that DTE projects savings of $51 million by 2028; his savings estimate assumes only 50% of that amount spread over ten years.[494] These adjustments to the historical averages are shown in Exhibit S-9.2.

Mr. Derkos emphasized that the intent of Staff's analysis was to adjust DTE's 2015 historical expense level, not to adjust DTE's requested expense allowance.[495] He also cautioned that DTE should not replace equipment simply due to aging, but replace it when it becomes economical to do so or when it suffers "unacceptable reliability".[496]

[494] See 5 Tr 1465-1466.
[495] See 5 Tr 1463.
[496] See 5 Tr 1466.

Mr. Coppola recommended a $24.6 million reduction to DTE's projected distribution system O&M expenses, eliminating $19.7 million in inflation included in DTE's expense projection and an additional $3.9 million in overhead line maintenance expense, for a total electric distribution O&M expense projection of $283.4 million as shown in Exhibit AG-6. He testified that the $3.9 million reduction is the result of an updated five-year average (2011 through 2015) to project overhead line maintenance expense.[497] As discussed above, Mr. Coppola also recommended that the Commission reject DTE's request for a regulatory asset with an $893,000 amortization of its proposed ETTP expenses, and he did not recommend that the Commission increase DTE's O&M expense allowance for the ETTP program.[498]

In his rebuttal testimony, Mr. Whitman presented additional information in his Exhibit A-28 regarding historic spending levels. He testified Staff incorrectly calculated an adjustment for tree trim funding that did not fully adjust the historical averages to reflect an equivalent $75.175 million tree-trimming expense:

> Exhibit A-28, Schedule R1 shows that DTE Electric's tree trim cost included in the 2011 to 2015 average is $56.0 million, inflation adjusted to mid-2017 using the inflation rates used by the MPSC Staff. The $11.5 million adjustment calculated by the MPSC Staff combined with the $56 million included in the 2011 to 2015 average provides $67.5 million for tree trim. This is $7.7 million less than the $75.175 million that Staff intends, and $15.3 million less than the $82.8 million that is necessary and prudent to trim trees on a reasonable cycle and improve DTE Electric system reliability.[499]

He also testified that Staff excluded critical factors when determining tree trim cost per mile because it did not consider DTE's projected increases in complexity and circuit

[497] See 6 Tr 1789-1790.
[498] See 6 Tr 1789-1790.
[499] See 3 Tr 361-362.

mix.[500] Mr. Whitman also contended that Staff misapplied DTE's avoided O&M cost analysis in incorporating a savings component in Staff's adjustment.[501]

In its briefs, DTE relies on Mr. Whitman's testimony in arguing that Staff and the Attorney General do not provide adequate funding for the company's overhead line maintenance expense. Regarding the Attorney General's recommendation, DTE argues that the Attorney General's adjustment to the overhead line expense category based on historical averages is a selective adjustment and argues that if updated historical averages are used for all categories of distribution O&M expense, the result would be to increase DTE's projection by approximately $1 million. DTE also objects to the Attorney General's refusal to provide additional spending for the ETTP program.

Regarding Staff's recommendation, DTE argues that it is "based on a flawed methodological construct." DTE contends that although Staff intended to provide tree trimming expenses of $75,175,000, Staff actually provided only $67.5 million in tree trimming costs, which DTE characterizes as "$7.7 million less than the $75.175 million that Staff intends, and $15.3 million less than the $82.8 million that is necessary and prudent to trim trees on a reasonable cycle."[502] DTE also argues that Staff's use of 2015 unit costs do not consider that DTE expects unit costs to increase as it moves to a different mix of circuits and as the time between trimming cycles increases the work complexity. DTE argues that Staff's savings estimate is "premature at best" because "avoided cost savings will be realized when there is proper funding of the ETTP." [503]

[500] See 3 Tr 362-365.
[501] 3 Tr 364-365.
[502] See DTE brief, page 56.
[503] See DTE brief, page 58.

DTE also cites Mr. Whitman's testimony in arguing that the ETTP increases reliability and will benefit customers in the long run.[504]

Staff's brief addresses DTE's arguments, indicating that Staff does not agree that its calculations provide DTE with $7.7 million less than Staff intended. Staff argues that DTE wrongly adds Staff's $11.5 million increase to the $56 million 2015 expenditure shown in Exhibit S-9.1, although Staff's adjustment is added to the entire inflation-adjusted account 593. Staff argues that its distribution O&M expense allowance of $317,508,000 reflects an increase over 2014 and 2015 levels including adjustments for inflation, restoration costs, and increased preventive maintenance and tree trimming. Staff characterizes DTE's request for an additional $16.5 million as unreasonable given its recent downward spending trend.[505] Staff reviewed the Commission's decision in Case No. U-17767, and argued that DTE did not support the reasonableness and prudence of its distribution O&M expense request in this case either:

> The Company claims that it will show benefits to customers of up to $51 million per year from the ETTP, however, the data the Company relies upon is aspirational at best and does not alleviate the concerns the Commission raised in rejecting the EVMP. (3Tr 306-307.) The Commission stated:
>
> > [T]he Commission also agrees with the Staff that without a benefit/cost analysis and a longer-term trial basis to demonstrate improved and sustained reliability, it is unreasonable to approve the entire EVMP expense. Therefore, the Commission finds it prudent to adopt the ALJ's recommendation of $11.25 million, as an O&M expense, to fund a pilot program. In addition, DTE Electric shall collect and report to the Staff data that measures the cost and reliability benefit compared to the benefit of DTE Electric's traditional vegetation management program. [MPSC Case No. U-17767, 12/11/15 Order, p 63.]

[504] See DTE brief, page 58.
[505] See Staff brief, pages 57-58.

> But, the Company did not conduct a pilot program. Rather, the Company proposes in this case that the Commission should fully fund ETTP, and that the Company "plans to establish a pilot program." (3 TR 314.) Yet the Commission found it unreasonable to approve the EVMP (now rebranded ETTP) without conduct of a pilot program *first*.[506]

Staff also notes that without a pilot program, DTE's implementation of the ETTP varied widely from its expectations, and fell far short of its mileage goals.[507]

Addressing DTE's objections to its use of 2015 units costs, Staff argues that the various tables in Mr. Whitman's testimony that DTE relies on are not reliable and do not take into account his references to "expected productivity gains" and "continuous improvement opportunities."[508] Staff argues:

> Given the uncertainty inherent in using hypothetical numbers, and numbers extrapolated from hypothetical numbers, the Staff finds the Company's average unit cost unreasonable. This is especially true where, as here, the Company admits that its initial experience with very limited use of enhanced tree trimming over a partial year was not in line with Company expectations, and the Company has not conducted a pilot program (3 TR 314) as the Commission requested.[509]

In its reply brief, Staff addresses DTE's criticisms of its $2.5 million savings estimate in part as follows:

> DTE Electric is taking an all or nothing approach to applying a $51 million projected savings to restoration cost savings. The Company states these savings would come from a reduced number of outages, which would cause less truck and crew deployment. This is a direct result from increased tree trimming. The Company claims that it will not realize any savings until the end of the program in 2028. (3 TR 306.) Thus, the Company claims the savings are premature. (DTE Electric's Initial Brief, p 58.) But, the Company's claim is just not credible. Staff recognizes that an estimate of these savings is hard to predict with exactitude, and thus made a conservative estimate that the yearly savings will be about half of DTE Electric's estimated yearly savings spread over a ten year period, or $2.5 million during the test year. (5 TR 1466.) Even though DTE Electric

[506] See Staff brief, page 61.
[507] See Staff brief, pages 62, 64.
[508] See Staff brief, page 63, citing Whitman, 3 Tr 302-305.
[509] See Staff brief, page 63-64.

> has not provided a cost/benefit analysis for ETTP program, its witness did testify that the results DTE Electric has seen are showing less outages in the first year of the program. (DTE Electric's Initial Brief, p 58; 3 TR 312.) Less outages mean restoration cost savings. Therefore, savings would begin at this time, and Staff's restoration cost savings reduction is not premature. The ALJ and the Commission should reject the Company's criticisms of Staff's restoration cost savings adjustment to Account 593.[510]

This PFD finds that Staff's recommended distribution system O&M expense allowance is reasonable and should be adopted. As Staff argues, DTE has not established the reasonableness and prudence of its proposed ETTP spending. DTE did not complete a pilot program. DTE relies only on two small examples to justify its projected spending on this program. The first example dates to 2011:

> A circuit in the Howell service territory was trimmed in 2011. The majority of the circuit, which has a total overhead length of 38.73 miles, was trimmed to the Company's prior specification. Exhibit A-21, Schedule M4 (page 1) shows pictures of these areas taken in early 2016. Note that after five years, the trees have grown back into the conductors. The balance of the circuit (approximately 1 mile) was trimmed to the Company's enhanced specification in 2011. This was done in response to a specific reliability issue regarding frequent outages and downed wires on their property. Exhibit A-21, Schedule M4 (page 2) shows pictures taken in early 2016 of the portion of the circuit trimmed to the enhanced specification. Note that after five years, the clearances have been maintained and low-cost mowing is now possible. This section of the circuit has experienced a 75% reduction in tree-coded interruptions during the five years since trimming as compared to the five years prior to trimming.[511]

Nothing in DTE's analysis explains why it is reasonable to extrapolate from this example: it provides no meaningful analysis of what else may have happened on that circuit. It does not establish that the circuit was properly trimmed and maintained over the first five-year period and it does not explain the source of the tree-coded interruptions during the five years since the trimming. In short, it leaves many

[510] See Staff reply brief, page 21.
[511] See 3 Tr 313.

unanswered questions. Similarly, DTE's second example relies on 6 months of experience with 11 circuits trimmed to the ETTP standards, less than a full year and less than four seasons, with no analysis of what else has gone on with those circuits in terms of other repair or maintenance work, "trouble tree" work, or storm activity:

> To date, the Company has trimmed 133 circuits to the enhanced specification. Of this group, there are eleven circuits for which the Company has at least six months of reliability data post-trimming. For these eleven circuits, the average reduction in tree coded interruptions/month (since trimming vs. year prior to trimming) was 78%. The average reduction in tree-coded outage minutes per month for the same comparison period was 97%. This is significantly better than the historical improvement seen under the Company's prior approach to trimming. On average, circuits trimmed to the prior standard specification experienced 50% fewer tree-coded interruptions/month after trimming compared to the year prior to trimming.[512]

Neither of these examples constitutes a study. Mr. Whitman also presented pictures in his Exhibit A-21, Schedule M2, to illustrate the different circuit trimmings. But again, there is no picture and no evidence establishing what the lines depicted there looked like when they were first trimmed, to support the claim that the trees had grown too close to the lines within the first year.

Given the absence of a pilot program and any meaningful data, DTE also has not established that its cost estimates for future tree trimming work will increase as projected in Mr. Whitman's charts. Mr. Whitman gave a conceptual explanation of how trimming on a seven-year cycle would increase costs, and then provided DTE's cost estimates in his Table 5 without explaining how the cost estimates are derived.[513] Mr. Whitman identified as one of the company's goals to "[u]nderstand the species and

---

[512] See 3 Tr 312.
[513] See 3 Tr 300-302.

density of trees on the entire distribution system to drive appropriate planning and work scheduling."[514] In that context, he explained:

> The Company's historical practice has been to target a five-year trimming cycle on most distribution circuits and a three-year cycle for all subtransmission circuits. However, the density and mix of trees along the Company's rights-of-way varies significantly across the service territory and even within a given circuit. Therefore, *the optimal trimming cycle may be different by circuit or by portions of a given circuit*.[515]

With reference to his Table 7, which presented estimates of the future costs of trimming including work complexity and circuit mix, Mr. Whitman also testified:

> The Company estimates the average cost per mile in 2016 to be $14,397 based on density analysis by region, recent actual costs and expected productivity gains*. Continuous improvement opportunities identified in the past year may bring the long-run average cost per mile down*. These improvements are expected to be implemented from 2016 through 2018, and include ideas such as optimizing removals, improving contractor efficiency and refining data around tree density and species mix.[516]

In its brief, Staff also correctly notes some incongruities in Mr. Whitman's charts. Table 5 looks at costs per line mile if DTE trims 4,150 miles annually moving forward and shows a 2017 cost per mile of $15,496,[517] while Table 7 projects a 2017 per mile costs of $17,209 per mile to achieve DTE's targets over the next few years;[518] likewise for 2018, Table 5 predicts a per mile cost of $16,536, while Table 7 predicts a per mile cost of $18,071.

Mr. Whitman's testimony also indicates several opportunities for more immediate savings. He explained how the software would assist the company to be more efficient:

> Similar to other utilities, the Company's tree trim work has been managed on a circuit-by-circuit basis using mostly paper processes that makes

---

514 See 3 Tr 296.
515 See 3 Tr 296 (emphasis added).
516 See 3 Tr 303-304 (emphasis added).
517 See 3 Tr 302.
518 See 3 Tr 304.

scheduling and routing cumbersome. Moving forward, the Company is implementing an industry proven software-based work management system. This will facilitate scheduling down to portions of circuits on appropriate cycles and efficiently routing tree trim crews.[519]

Regarding the use of software, he also testified:

> During 2015, the tree trimming team began implementing a software solution to manage the workflow associated with ETTP. The result will be an end-to-end solution for all aspects of tree trimming activities, bringing DTEE and contractors onto a single integrated platform. The solution will provide clear real-time visibility of all aspects of tree trimming and improve the efficiency and accuracy of all phases of the Company's tree trimming process. The improvements and transparency from the software will benefit the following programs: Cycle Trim, Trouble, Storm, New Business, CEMI4, Pole Top Maintenance (PTM), Project Work and System Resiliency. This initiative was driven by benchmarking of other relevant utilities with better reliability and sustained performance.[520]

Note that DTE's capital expense budgets include "reliability IT" spending as described by Ms. Uzenski and there is also a line item for IT in Mr. Whitman's workpaper included in Exhibit AG-17.

Mr. Whitman also testified at 3 Tr 314-315 that DTE now intends to establish a pilot program, identifying the following "key elements":

> 1. Selection of specific circuits to comprise the pilot program;
>
> 2. Enhanced trimming and tree removal on selected circuits, including removal of hazard trees;
>
> 3. More in-depth root cause analysis of outages on circuits within the scope of the pilot program.

He does not evaluate whether the difficulties DTE encountered in 2015, as described above, could have been avoided with a properly-designed pilot program.

While DTE clearly would like the additional expense allowance, Staff's allowance provides for an increase over recent spending through use of the five-year average

[519] See 3 Tr 296.
[520] See 3 Tr 316.

adjusted for inflation; it provides for additional expenditures for three programs aimed at improved reliability, the "trouble tree" program and the preventive maintenance of both stations and underground lines; and it provides a significant additional increase of $9 million for expanded tree trimming, counting the $2.5 million savings estimate. The inflation-adjusted five-year-average expenditure in DTE's FERC account 593 is $148,168,000 with inflation through the projected test year.[521] Staff's expense allowance of $157,208,000 for this account, after all adjustments, is an additional 6.1% above that amount. Staff's expense allowance for this account is also 28.3% above the $122,459,463 DTE actually recorded for 2015. For the entire category of expense, Staff's recommended allowance of $317,508,000 is 5.2% above the five-year inflation-adjusted average of $301,779,000 computed in Schedule S-9.2, line 25, columns c, d, and e, and 18.9% above DTE's actual reported expenditures for 2015 as shown in Exhibit S-9.0. DTE's complaints about alternate methods of calculating an adjustment are not persuasive. There is no mathematical precision that is called for. Likewise, the minor reduction in Staff's increase to historical inflation-adjusted expense levels to reflect potential savings is clearly reasonable in light of Mr. Whitman's own testimony regarding DTE's plans to improve efficiency utilizing new software, even without regard to reliability improvements, which DTE has also projected. Conversely, this PFD recommends that the Commission adopt Staff's adjustment rather than the Attorney General's, because Staff has considered the impact of inflation on historical expense levels, and well as an appropriate allowance for tree trimming, as discussed above.

In addition, it is appropriate to note that DTE's projected benefits from its ETTP were based on the expectation of a 40% reduction in SAIDI over its 2013 levels by

[521] See Staff's Exhibit S-9.2, line 18, columns c, d, and e.

2028. Mr. Whitman explained this in his direct testimony.[522] Mr. Wuepper's testimony, however, indicates that the 2015 SAIDI was 275 minutes, which is more than 40% below DTE's 2013 SAIDI of 583 minutes, as shown in Mr. Whitman's chart.[523] Mr. Wuepper also explained that SAIDI is heavily influenced by storms. The apparent lack of meaningful goals or targets for overhead line maintenance expense is another reason why the Commission should be concerned with DTE's distribution system planning and analysis, as discussed in section IV above.

8. <u>Customer Service and Marketing (Exhibit A-10, Schedule C5, line 7)</u>

Schedule C5.7, page 1 includes customer accounts expense, customer service expense, and sales expense. Ms. Uzenski testified that she directed Mr. Sparks to include $3 million in economic development expenses discussed by Ms. Dimitry in his Schedule C5.7, in Account 912.[524] She testified that this account is for "expenses incurred in promotional, demonstrating, and selling activities, except by merchandising, the object of which is to promote or retain the use of utility services by present and prospective customers." Ms. Dimitry testified that the company's proposal to add economic development tools, staff, marketing materials and activities to its existing economic development team arose from a "benchmarking" activity with other utilities:

> In early 2015, senior leaders from DTE Energy and members of its economic development organization met representatives of Georgia and Alabama Power utilities to benchmark their economic development activities and research their best practices. Members of that team conducted further research on the economic development activities of the Tennessee Valley Authority (TVA) and Entergy utilities. All four companies are consistently ranked as some of the top utilities for economic and business development by site selectors and other commercial and industrial developers. DTE Energy found that all four utilities invest

---

[522] See 3 Tr 306.
[523] See 4 Tr 948.
[524] See 4 Tr 815; also see Sparks, 4 Tr 1013.

considerably more resources in business development activities than DTE Electric does, and implemented those activities through their respective economic development organizations. For example, both Georgia Power and TVA have economic development staffs of over 20; these larger staffs allow each utility to focus on building relationships across multiple industries and geographic regions. This focus helps them bring businesses to their service territories that increase load growth, thus spreading their fixed costs over a larger customer base and lowering rates for existing customers. For example, automotive industry business developers from TVA actively recruit auto companies in Michigan to relocate to TVA's service territory; Georgia Power has employees that focus on recruiting businesses from countries outside of the United States and also maintain their state's economic development database, analytics, and website; and, Entergy has developed and maintains a robust building and site database that provides companies across the world access to information on available properties, infrastructure, and partner organizations to help their expansion or relocation.[525]

Ms. Uzenski also indicated that currently, DTE has a staff of four economic developers and has relied on support from partner organizations and state agencies to provide similar types of services offered by the four utilities mentioned above. She further opined that DTE's increased activities "are critical for the Company and for the State of Michigan to compete for business and load growth with the best-in-class utilities across the United States."[526] She also described some of the success stories provided by those four utilities.

To explain what DTE would do with the additional funding, she testified:

DTE Energy will use these incremental funds to expand its economic and business development staff as well as fund and support economic development programs and activities that will be geared toward attracting and expanding businesses within the State of Michigan, and within DTE Electric's service territory. Some of these activities will include: 1) Supporting outreach activities needed to attract businesses to the State; 2) Enhanced retention and expansion efforts with our largest customers; 3) Developing marketing programs and materials used to promote Michigan as a great place to do business; 4) Conducting research and commissioning studies used to promote the assets and infrastructure of

[525] See Dimitry, 3 Tr 230-231.
[526] See 3 Tr 231

> the State and DTE Electric; 5) Sustaining and developing databases and information repositories or websites with information valuable to site selectors, such as available commercial sites.
>
> As part of DTE Energy's plan to expand its economic and business development activities, it is expected that a number of DTE Energy's economic and business developers will interface with state and regional organizations, and then help guide program development and strategic planning that ensure the State and regional partners are attracting companies that will have a positive impact on the Company's customers. These DTE Energy employees will actively seek out companies that would benefit by relocating or expanding their operations within the State of Michigan. Additionally, DTE Energy will provide critical energy related information about its business and the benefits it can provide to potential customers, which is typically used as businesses decide whether to locate, or expand in Michigan.[527]

She believes DTE customers will benefit from DTE's efforts in the following ways:

> DTE Electric's economic development activities will benefit customers in multiple forms. The primary goal of DTE Electric's economic development efforts is to increase load growth and sales through the expansion of businesses in the State of Michigan. The increase in electric sales helps spread fixed costs across more customers which could reduce rate pressure on all customers. As rates become more affordable, it is expected that the level of uncollectible accounts will decline, further reducing costs. Additional indirect benefits include: 1) Increased jobs, which will create more opportunities and improve wage growth for customers, helping the state and local municipalities attract and retain workers; 2) Improvement of local economies, leading to higher home values, larger tax base, and better funding for schools; 3) Improving customer understanding of the importance of energy in both their lives and in the economic wellbeing of their communities, helping to further engage them in the work the utilities provide.[528]

Mr. Nichols testified that Staff does not support DTE's request to include $3 million for economic development activities in test year O&M.[529] Mr. Nichols testified that although DTE identified other utilities with larger economic development staff than DTE has, DTE could not identify their total expenditures or the amounts they recovered

[527] See 3 Tr 233-234.
[528] See 3 Tr 234-235.
[529] See 5 Tr 1526-1530.

through rates. He also discussed the activities of the Michigan Economic Development Agency, its core focus, its scorecard with performance metrics, its $39 million budget, and its $3 billion target for private investment.[530] He testified that Staff opposes DTE's request for additional economic development funding because DTE does not have any performance metrics to measure the success of a potential program, its activities appear duplicative of MEDC activities, it could put other utilities who do not have ratepayer funding at a disadvantage, and economic development is not a core utility function.[531]

The Attorney General also objected to the additional funding for economic development activities for similar reasons:

> The request appears to be an attempt by the Company to proactively initiate its own economic development searches and marketing activities to potentially lure additional customers to its service area. The additional activities would likely include Company's employees going to other states and perhaps foreign nations to prospect for customers. It is hard to understand how such proactive economic development activities fit with the basic core function of providing utility services. Although customer and sales growth is always welcomed, the proposed expansion of economic development activities goes too far afield from that core function. The State of Michigan has a very active and effective economic development department and other local government units also have or support economic development activities. The Company's proposed program would likely be duplicative of those government activities.[532]

Staff and the Attorney General rely on these analyses in their briefs.

Mr. Zakem also testified on this issue, from the perspective of the choice customers. He testified:

> As a regulated utility, DTE is in the business of providing and delivering safe and reliable electric energy to its customers. Regulation assures that

[530] See Tr 1527-1529, and Exhibit S-11.1.
[531] See 5 Tr 1529.
[532] See Exhibit AG-7, 6 Tr 1790-1791.

> the owners of DTE – the stockholders – are compensated for reasonable and prudent expenses and for a return on used and useful investment.
>
> DTE as a regulated electric utility is not a state agency; it has no taxing authority; it has no oversight by voters. It has no duty to provide staff services in the form of analytics, databases, or land information for any governmental agency or other organization that it believes needs more resources. It has no authority to decide what the State of Michigan's policy should be; it has no obligation to implement what it believes to be a productive economic policy for any governmental unit, let alone charge its electric customers for that activity. Allowing DTE to charge its customers for economic activities in support of state agencies amounts to creation of an economic development tax that only DTE customers are being asked to pay.[533]

He also testified that if the Commission nonetheless approves the company's proposal, it should carefully consider how to allocate these costs:

> If the Commission decides to allow DTE to recover the additional money for economic development from its electric customers, then I recommend (a) that the requested amount should first be split between power supply and distribution on the basis of relative dollar investment, and (b) that after the split, the power supply amount should be allocated to power supply customers by power supply sales in each rate class and collected in power supply rates, and the distribution amount should be allocated to distribution customers by distribution sales in each rate class and collected in distribution rates.[534]

Energy Michigan urges the Commission to adopt Mr. Zakem's recommendations in its brief.

DTE argues in its briefs that economic development activities would benefit the State of Michigan and the company's customers through the spreading of fixed costs, but does not address the specifics of the Staff, Attorney General, and Energy Michigan concerns. For example, DTE contends that the requested funds are "critical" for DTE Electric and Michigan to compete for business and load growth with best-in-class

[533] See 6 Tr 1716-1717.
[534] See 6 Tr 1717-1718.

utilities across the state, but does not address Mr. Nichols's careful review of the Michigan Economic Development Corporation.

This PFD finds that the additional economic development funding should not be included in rates. DTE has not established that its efforts will not be duplicative of other efforts, nor has it articulated a feasible limitation that would preclude it from seeking customers of other Michigan utilities. Considering DTE's core functions as discussed above, there are many pressing issues facing DTE, including integrated resource planning and distribution system reliability, which fit more squarely within the utility's core functions.

9. <u>Uncollectible Expense (Exhibit A-10, Schedule C5, line 8)</u>

Mr. Sparks presented DTE's projected uncollectible expense projection of as shown in line 8 of Schedule C5 and in Schedule C5.7, page 2. He explained the accounting for uncollectible expense, and also explained that DTE has reduced the amount of time between a customer falling into arrears and shutoff of service to that customer in accordance with the applicable billing rules.[535] In addition, he explained efforts DTE has undertaken to improve its collection effectiveness, find sources of low-income funding, and promote efficiency and conservation for low-income customers.[536] Mr. Sparks testified that DTE is projecting uncollectible expense of $49.2 million, based on a three-year average, "[reflecting] our planned efforts to sustain our results despite continuing economic challenges for many of our customers."[537]

[535] See 3 Tr 1015-1016.
[536] See 3 Tr 1016.
[537] See 3 Tr 1017.

Mr. Sparks also testified that the 2014 results were "normalized" to reflect $2.9 million in proceeds from a 2014 sale of debt.[538]

Mr. Welke presented Staff's recommended test year uncollectible expense projection. He testified that Staff also used a three-year average, but updated to include the 2013 to 2015 time period rather than the 2012-2014 period used by DTE. He testified that Staff's three-year average includes a portion of the proceeds from a debt sale in 2008.[539] Mr. Welke testified that Staff's recommended uncollectible expense projection results in a $3.3 million increase in DTE's revenue requirement.

No other party made a recommendation for this expense itme, although the Attorney General recommended an adjustment to the projected uncollectible expense amount attributable to AMI savings, which is discussed below. In its initial brief, DTE indicated it agreed with Staff's adjustment.[540] Therefore, this PFD considers this matter resolved.

10. <u>Corporate Support (Exhibit A-10, Schedule C5, line 9)</u>

The supporting detail DTE presented for line 9 of Schedule C5, labeled "Corporate Support", is contained in Schedule C5.8, which identifies the following categories of expense: salaries, property insurance, injuries and damages, and general advertising. Mr. Uzenski presented testimony in support of the company's expense projections in these categories. The items disputed on the record include the inflation factors used, incentive compensation, injuries and damages, property insurance, and advertising expense. As discussed below, some of these issues have been resolved through the briefs of the parties.

---

[538] See 3 Tr 1017; also see Uzenski, 4 Tr 808.
[539] See 5 Tr 1576.
[540] See DTE brief, page 10.

a. *Inflation*

Ms. Uzenski described the organizations and activities falling within the Corporate Support Group and explaining that the Corporate Support Group provides a variety of “Administrative and General” (A&G) services to DTE. For this category of expense, not including benefit expense addressed by Mr. Wuepper, Ms. Uzenski explained the adjustments made to historical expenses to exclude costs recovered through the renewable energy program, other costs DTE excluded or the Commission has disallowed, and other “normalizing” adjustments.[541] She testified that she applied DTE’s weighted inflation rates to the adjusted 2014 historical costs, except the separately projected property insurance and injuries and damages categories, with an additional adjustment to reflect an accounting change to the company’s “performance shares” long-term incentive programs.[542] And, she explained how these costs are allocated to DTE and other DTE Energy subsidiaries.

Staff recommended a $7 million inflation adjustment to the Corporate Support expense projection. Mr. Welke testified that Staff used 2015 historical expenses as the basis for its projection with Staff’s inflation factors through the projected test year.[543] Consistent with his recommendations on inflation, as shown in his Exhibit AG-8, Mr. Coppola recommended that the Commission exclude the $11.2 million component of DTE’s expense projection, or $6.9 million not including inflation associated with DTE’s incentive compensation request, which is discussed separately below.[544]

---

541 See 4 Tr 824.
542 See 3 Tr 825.
543 See 5 Tr 1574-1575. See Staff brief, pages 66-67.
544 See 6 Tr 1792.

This PFD recommends that the Commission adopt Staff's recommendations, including Staff's use of 2015 data and Staff's inflation factors, for the reasons discussed above.

b. Incentive Compensation

Certain of DTE's incentive compensation programs are included in the Corporate Support category of expenses. These are the Long-term Incentive Plan (LTIP), the Annual Incentive Plan (AIP) and the Rewarding Employees Plan (REP). Mr. Wuepper testified in support of DTE's benefit projections, including DTE's request to recover projected expenses associated with its incentive compensation programs, with the exception of the incentive compensation program expenses for DTE Energy's top five executive officers. Mr. Wuepper identified the 2016 metrics for each of the plants, with projected expenses for "target-level" performance totaling $39.4 million.[545] He presented a cost-benefit analysis in Exhibit A-20, Schedule L5.

Mr. Wuepper acknowledged that the Commission did not authorize recovery of the short-term incentive compensation expense related to financial measures and did not authorize recovery of the long-term incentive compensation expense in Case No. U-17767, but he also cited the Commission's order setting rates for Consumers Energy in Case No. U-17735. He argued that DTE's variable pay programs are similar to the programs at Consumers Energy. He also testified that the benefits associated with DTE's financial metrics justify the expenses.

[545] See 4 Tr 954.

Mr. Welke presented Staff's recommended adjustment reducing DTE's projected incentive compensation expense by approximately $23 million.[546] He explained:

> Staff's Incentive Compensation Expense adjustment is based on the Commission's most recent DTE Electric order, MPSC Case No. U-17767, dated December 11, 2015. In that order, the Commission found that the portion of Incentive Compensation Expense that is tied to financial metrics largely benefit shareholders, and that because of this, should not be paid for by ratepayers.

The Attorney General recommended excluding all DTE projected expenditures for incentive compensation.[547] Mr. Coppola testified that DTE seeks to recover $45.1 million of employee incentive payments, with information on the 2016 incentive plan presented in Exhibit A-20, Schedule L5, 27% relates to "long term incentive plan", 19% to "Annual Incentive Plan", and 54% to the "Rewarding Employees Plan".[548]

After identifying the measures for the AIP for 2016, he testified that a review of the measures in place for the prior five years reveals that certain measures and target levels have varied from year to year, making direct comparison more challenging. Regarding the REP, he testified it is similar, but the AIP is for senior level managers while the REP coverall all other employees.[549]

Mr. Coppola testified to his opinion that all three plans are too heavily skewed toward measures that directly benefit shareholders and not customers. Additionally, he testified that the customer benefits identified by the company are based on a faulty premise of historical cost savings and an expectation that future targets of performance

546 See 5 Tr 1575-1576; also see Staff brief, pages 67-69.
547 See 6 Tr 1792, 1796-1803, Exhibit AG-8.
548 See 6 Tr 1796.
549 See 6 Tr 1797.

will be achieved.[550] Regarding the AIP and REP, he objected to the reliance on financial measures:

> [H]alf of the incentive payout at target level relates to the Company and its parent, DTE Energy, achieving net income, earnings per share and cash flow goals. Despite the argument by the Company that achieving these goals somehow benefits customers, there is no direct relationship to customer benefits. These goals are in place to maximize profits and increase cash flow to pay dividends to shareholders. It is even more inappropriate to charge customers for incentive pay costs related to achieving DTE Energy earnings per share since those earnings include earnings from the gas and non-utility businesses of DTE Energy. The Commission should not allow recovery of incentive payments related to these financial goals.[551]

Regarding the "customer satisfaction" measures, he testified that this category represents just 16% of the total compensation and "the benefits achieved are far less than the costs as measured by the Company." And, regarding the "Employee Engagement" category, he testified that although the measures contain worthy goals "they do not rise to the level of being measures that are visible to customers nor do they create customer benefits."[552] Finally, with regard to the "Operating Excellence" category, Mr. Coppola testified that the measures are basic operating goals: "the only measures that have a direct link to customers are the Electric Distribution Response Time metrics which represent approximately $310,000 of the expected payout."

Mr. Coppola took issue with the analysis Mr. Wuepper presented in Exhibit A-20, Schedule L5:

> Mr. Wuepper has shown a calculation which purports to show that recent operating and financial cost savings are exceeding adjusted incentive plan payments by $183 million. However, the largest net benefit showing in this exhibit lie in the areas of (1) Operating Excellence ($149 million); and (2) the Financial Measures ($27 million). Clearly these metrics involve

[550] See 6 Tr 1798.
[551] See 6 Tr 1798-1799.
[552] See 6 Tr 1799.

> shareholder satisfaction. In contrast, the benefits vs. expenses related to the Customer Satisfaction metrics shows a net loss of $5.0 million (line 23 of this exhibit). Mr. Wuepper provides little assurance through his testimony that this measure can be achieved with any consistency in the future and therefore, the Commission should not base its decision to grant approval for recovery of more than $45million of incentive compensation costs on such poor historical performance.
>
> In summary, my assessment is that the Company has failed to show that it has achieved consistent performance at target levels in the key performance measures directly affecting customers (Customer Satisfaction and Customer Service Interruptions) and as a result the calculated potential benefits are purely theoretical and inadequate to justify recovery of incentive pay expenses.[553]

Recognizing the Commission's orders in Case Nos. U-17767 and U-17735 allowed DTE and Consumers Energy to recover a portion of their projected short-term incentive compensation expense, Mr. Coppola testified that every rate case has to be determined on the record presented in that case:

> Prior Commission orders in rate cases for Michigan utilities has required a preponderance of evidence for the Commission to be convinced that incentive compensation has created significant benefits for customers, above the ordinary level, for those costs to be recovered in rates. In my opinion, the applicants did not make a case sufficient enough to justify recovery of the proposed incentive compensation costs in Case Nos. U-17735 and U-17767. This is also true in this rate case. [554]

He also quoted the dissenting opinion from Case No. U-17735. In addition, he testified that if the Commission wished to include some of the projected expenditures in rates it should not be more than 52% of the total, or $17 million, relating only to the operating performance measures.[555]

Regarding the LTIP, Mr. Coppola testified that the 3 measures in the plan are strictly designed to induce management to create shareholder value. Quoting

[553] See 6 Tr 1801.
[554] See 6 Tr 1802.
[555] See 6 Tr 1803.

Mr. Wuepper's testimony at 4 Tr 952, that these measures are intended to motivate employees to keep in mind the role of their own contributions to the overall long-term success of DTE Energy, Mr. Coppola testified that DTE customers should not pay for the overall success of DTE Energy.[556]

Mr. Zakem also objected to including incentive compensation for financial metrics in rates. In his view:

> For any rate-paying customer to pay a bonus to a utility for increasing earning per share, total return to shareholders, and the other financial goals is illogical and violates the principle of paying for a shared benefit. Such a system forces ratepayers to reward the utility for making them pay more, as the earnings are earned on the ratepayers' backs, so to speak. Moreover, increased earnings per share benefits stockholders, not customers. Therefore, if there is to be a payment to utility employees for meeting financial goals that benefit stockholders, the payment should come out of stockholder earnings, not customer rates. [557]

In his rebuttal testimony, Mr. Wuepper objected that Staff and the Attorney General did not properly regard the substantial benefits he identified related to DTE's financial measures. Regarding Mr. Coppola's broader recommendation to exclude all projected incentive compensation expense, Mr. Wuepper characterized Mr. Coppola's testimony as "performing a critique of the Commission's orders." He also reviewed the elements of his cost-benefit analysis. [558]

In his brief, the Attorney General addressed Mr. Wuepper's rebuttal testimony:

> In response to Mr. Coppola's criticism that that DTE's three incentive plans are too heavily skewed toward measures that directly benefit shareholders, Mr. Wuepper states that earnings and cash flow relate to the Company's current debt ratings which produces savings and that it is a benefit to customers for DTE to have access to the capital markets. (Tr 969.) The problem with Mr. Wuepper's rebuttal is that he misses the point of Mr. Coppola's testimony. Even though DTE's incentive programs

[556] See 6 Tr 1800.
[557] See 6 Tr 1720.
[558] See 4 Tr 969-974.

may provide useful metrics to measure performance internally for the Company, they do not provide direct benefits to ratepayers but rather an overall benefit to the company and its parent. It is not that there can never be a trickle down benefit to ratepayers, rather "linkage to the financial metrics that mostly benefit the company's investors does not, in my opinion, pass muster." (U-17735, Commissioner Talberg's dissent quoted in above with emphasis added). In fact, Chairman Talberg's quote effectively responds to Mr. Wuepper's rebuttal when she stated that "[w]hile it is [no] doubt important for customers to maintain a health utility, it seems logical at this point to require customers to support customer-oriented outcomes and for the shareholders to support short-and long-term financial outcomes." (U-17735, Commissioner Talberg's dissent.)[559]

DTE responds in its reply brief:

> Mr. Coppola's views are not aligned with the Commission's recognition that incentive compensation costs are recoverable, and also the need for Commission decisions to be based on the record.
>
> The AG also quotes the dissenting opinion in Case No. U-17735 for the proposition that ratepayers should fund only operating performance metrics that benefit customer service (AG Initial Brief, pp 29-30), but inconsistently with even that cost-recovery position, the AG completely opposes any recovery here because DTE Electric's incentive compensation programs have financial as well as operating metrics. The AG's inaccurate and inconsistent assertions defy reasoned analysis and cannot support a decision by the Commission.[560]

DTE also reiterates its claim that its entire program should be funded based on the Commission's decision in Case No. U-17735.

First, it is clear that DTE has not presented any analysis sufficient for the Commission to revise its determination that financial metrics are primarily for the benefit of shareholders and should not be funded by ratepayers. DTE did not present any new evidence in this case regarding the financial metrics that it did not present in Case No. U-17767. Indeed, Mr. Wuepper's cost-benefit analysis of the financial metrics in both the short-term and long-term incentive compensation plans in this case relies primarily

[559] See Attorney General brief, page 30-31
[560] See DTE brief, page 71.

on two “savings” estimates totaling approximately $50 million. First, he testified that DTE’s projected O&M expense level in this case “is $389.1 million less than if the Company’s O&M expense incurred in 2005 had increased by the rate of inflation, or an annual O&M expense savings of $33.3 million ($389.1 million/11.7 years).”[561] DTE has not provided an analysis to establish that it is reasonable to attribute that lower O&M expense level entirely to the incentive compensation program. Productivity increases in the economy are commonplace. Among other things, DTE’s analysis fails to consider any of the myriad capital expenditures funded by ratepayers over the years. Note that in its December 23, 2008 order in Case No. U-15244, the Commission used a rate base of $9 billion to set DTE’s rates. DTE’s projected rate base in this case is approximately $14.5 billion, as shown in its Exhibit A-8. In addition, note that in this case alone DTE is projecting capital expenditures from 2014 through the end of the projected test year of approximately $3.9 billion, as shown in Exhibit A-9, Schedule B6.

Also, contradicting DTE’s claim that the financial incentives in the compensation program are responsible for the identified savings, note that DTE has objected to estimates of cost savings being included in this case, arguing, for example:

> AG witness Mr. Coppola recommended removing all inflation (except a small amount related to employee health care expense) from O&M, reasoning that the Company was able to offset inflation in the past, so the Company should be able to also do so in the future (6T 1787). Mr. Coppola neglects to recognize that *prior cost reductions were significantly influenced by benefit design changes that reduced the Company’s Other Post Employment Benefits (“OPEB”) liability*. This item is no longer available since the savings created by these benefit design changes will be almost completely amortized by the end of 2016 (4T 916). The record also includes inflation data based on objective indices. In contrast, Mr. Coppola’s proposal is not based upon any data or evidence, so his subjective opinion should be summarily rejected as a matter of law (4T 850, 853-54).

[561] See 4 Tr 958.

Indeed, in this case DTE proposed the use of a non-traditional blended inflation rate. Rather than credit the financial metrics of the incentive compensation program for reducing O&M expenses, the Commission should be concerned that the financial metrics encourage the company to ask for more than it really needs.

The second source of savings Mr. Wuepper attributes to the financial metrics is the approximately $18 million in additional interest DTE believes it would pay if its debt rating fell from BBB to BBB-. Once again, the attribution of the maintenance of DTE's credit rating to the financial metrics in the incentive compensation programs ignores all the money the ratepayers contribute to maintain a capital structure and a rate of return commensurate with DTE's current credit rating. By failing to consider this, DTE has failed to justify this savings estimate. For these reasons, this PFD recommends that the Commission adopt Staff's recommendation to exclude the approximately $23 million in costs associated with the financial metrics from the expense projections in this case. This exclusion is also consistent with Mr. Coppola's alternate recommendation.

In response to DTE's concerns that it is being treated unfairly relative to Consumers Energy, this PFD notes that each case must be evaluated based on its own record, and the analysis in Case No. U-17735 has not been presented for review in this docket. Moreover, it is clear from a review of the Commission's order in Case No. U-17735 that the Commission authorized an expense of approximately $5.3 million in that case, significantly less than it authorized for DTE in Case No. U-17767, and significantly less than Staff's recommendation provides for in this case.[562]

[562] See November 19, 2015 order in Case No. U-17735, page 78.

While Mr. Coppola legitimately raises a concern with the other non-financial measures, this record does not contain any new information regarding those measures that is categorically different from the information available to the Commission in Case No. U-17767. Nonetheless, this PFD recommends that the Commission require an analysis of the actual payments relative to actual performance metrics in DTE's next rate case.

c. *Injuries and Damages*

In projecting injuries and damages expense for the test year, DTE used a five year average based on expenses through 2014. Mr. Welke testified that Staff also used a five-year average to project this expense category, but updated to the 2011-2015 time period. He testified that this results in a $3.96 million reduction to DTE's revenue requirement.[563] The Attorney General also recommended this adjustment.[564] In its initial brief, DTE agreed with this modification.[565] This PFD therefore considers this issue resolved.

d. *Property Insurance*

DTE also used a five-year average to project property insurance expense, as Ms. Uzenski explained:

> Due to the volatility in these accounts, I propose the use of a five-year average to determine the projected test year amounts for these accounts in order to smooth out any year over year variances. Property Insurance expense is impacted by distributions from our policy with Nuclear Electric Insurance Limited (NEIL) that periodically occur (but not every year) and cannot be forecasted. Historically, the Commission has utilized the five-year average for Injuries and Damages (I&D) and I believe it is also an appropriate method for Property Insurance. These adjustments result in a

[563] See 5 Tr 1576.
[564] See 6 Tr 1793.
[565] See DTE brief, page 10.

> $3.6 million increase in Property Insurance and a $7.6 million increase in I&D.[566]

Mr. Welke testified that a five-year average has not been typical for this category and is not appropriate because the expenses have been decreasing:

> Property Insurance Expense has been steadily decreasing from $13,041,401 in 2008 to $5,936,012 in 2015. The Company proposed a five–year average, which is a methodology that has never been used or proposed previously by the Company. The Commission has consistently used the historical test-year expense amount and applied inflation. Further, the Company's proposed methodology is in contrast to a clear downward expense trend for Property Insurance.[567]

Mr. Welke recommended that the Commission use the 2015 historical expense, adjusted for inflation, resulting in Staff's $2.1 million reduction to DTE's test year property insurance projection.

The Attorney General used a five-year average that incorporated updated 2015 data,[568] but also made a "normalizing" adjustment for NEIL mutual insurance distributions that DTE opposes on the grounds that a five-year average includes the impact of variable distributions.[569]

Ms. Uzenski provided rebuttal testimony to Staff:

> While it is true that the Company and the Commission have previously used a forecast based on the historical period plus inflation, that fact does not preclude the use of an improved methodology in this case. A five year average has been accepted by the Commission for other items that fluctuate such as Injuries and Damages and Restoration expense. Property insurance expense is impacted by distributions from mutual insurance arrangements. As shown on Exhibit A-30, Schedule T1, the amount of the distribution varies from zero to $2.6 million. This exhibit also shows that a downward trend cannot be assumed because 2015 expense is higher than 2014 expense. In addition, the price of insurance premiums can vary depending on the cost of claims the carrier experiences. Instead

566 See 4 Tr 825.
567 See 5 Tr 1577.
568 See 6 Tr 1793
569 See DTE reply brief, page 60.

> of the Staff's proposal, the Company would support an updated five year average that includes 2015 and results in a projection of $6,978,000 as shown in column (g), line 7. This is a reduction of $703,000 from the Company's filed position.[570]

She took issue with the Attorney General's adjustment based on his recommended treatment of the NEIL reimbursement:

> I agree with the update to include 2015 actual expense that results in a projection of $6,978,000 as shown on Exhibit AG-8, page 3, column (b), line 6. I do not agree with the normalization adjustment to impute NEIL distributions related to 2011 and 2012. The use of a five year average is intended to accommodate the variability in expense, including the impacts of inconsistent distributions, so a further normalization would be double counting the impact.[571]

In its brief, DTE reiterates the compromise identified in Ms. Uzenski's testimony, indicating that use of an updated five-year average is acceptable, but disputing Staff's use of 2015 property insurance costs. DTE relies on A-30 showing the variability in NEIL mutual insurance distributions to refute Staff's claim that a five-year average is not appropriate for this category of expenses.[572]

Staff argues that the Commission should adopt Staff's projection and reject the proffered compromise.[573] Staff argues that because property insurance expense has been steadily decreasing from 2008 to 2015, it is not volatile: "A steady decline is, by definition, not volatile, and it would unreasonable for the Commission to treat it as such. Furthermore, using an averaging methodology nullifies the benefit to ratepayers of a steadily decreasing expense."[574]

---

570 See 4 Tr 855.
571 See 4 Tr 855-856.
572 See DTE reply brief, pages 58-60.
573 See Staff brief, pages 70-71.
574 See Staff brief, page 71.

This PFD recommends that the Commission adopt Staff's recommended adjustment. DTE's stated reason for the change in methodology, to address volatility associated with the NEIL mutual fund distributions, does not make sense. Given the general downward trend of DTE's property insurance costs, it is reasonable to use the more recent cost data. DTE did not present any basis to conclude that its risk of property loss has increased. The NEIL mutual fund distributions can be addressed separately in a later rate case.

e. *Advertising*

Ms. Uzenski testified that DTE removed certain categories of advertising expense from the historical test year to be consistent with the filing requirements testifying that allowable advertising expenses for ratemaking include public safety, conservation, and billing practices.[575] She testified that these adjustments are also reflected in Schedule C5.8 of Exhibit A-10.

The Attorney General recommended reducing DTE's proposed expenses by $1.3 million to reflect his view that radio and television advertising were done to promote DTE's image rather than provide meaningful information to ratepayers:

> I have eliminated all of the Company's advertising costs except for amounts for public safety, AMI and billing inserts. The key difference in this area is the elimination of advertising related to conservation which can be accomplished via bill inserts. The Company is spending large amounts unnecessarily in frequent radio and television advertising which are more beneficial to corporate image building than necessary to communicate specific customer programs.[576]

Ms. Uzenski testified in rebuttal on this issue:

> The Company has already eliminated advertising expenses associated with general corporate messaging. The eliminated programs related to

[575] See 4 Tr 799-800; Exhibit A-3, Schedule C8.
[576] See 6 Tr 1793.

> DTE's commitment to renewables, involvement with the community, efforts to improve customer service, and support of Michigan's economy. The advertising expenses included in the Company's projected costs were for campaigns to inform customers about available tools and tips to conserve energy, and billing options such as automatic bill payment and budget wise billing. As to the delivery method for this information, bill inserts are not sufficient. *Some customers choose not to receive a paper bill and therefore do not receive the bill inserts; and some customers that do receive a paper bill do not read the inserts.* The use of a variety of communication channels, including media, is necessary to make sure the information reaches as many customers as possible. Therefore, the AG's proposal to eliminate all media advertising should be rejected.[577]

In his brief, the Attorney General disputes that customers not receiving a paper bill justify the additional advertising expense. The Attorney General cites Ms. Uzenski's cross-examination at 4 Tr 881-883, acknowledging that she could not say how many customers do not receive paper bills, and also providing her understanding that these customers generally receive an electronic bill or have access to electronic communication from the Company and could be informed of all the energy efficiency programs through this electronic communication. (Tr 881-883.)

In its reply brief, DTE argues:

> The AG responds by suggesting that customers who receive electronic bills or otherwise have access to electronic communications could be informed by electronic communications (AG Initial Brief, pp 21-22, citing Ms. Uzenski's testimony on cross examination at 4T 881-83). The AG's suggestion is overstated because it assumes that customers would be adequately informed by just this one method. The AG also mischaracterizes Ms. Uzenski's testimony, ignoring her explanation that "we want to use various mediums or channels to communicate with our customers, including our television and radio ads, which we do a lot of safety messaging, especially through radio and TV. So we are trying to reach as many customers as we can using various channels because we know not everybody is going to receive the information on just one channel" (4T 882) . . . "we want to make sure that all our customers hear those safety messages. And I – I think the more channels we use to

[577] See 4 Tr 856.

communicate that, the better" (4T 883). Thus, the record demonstrates that the AG's proposal is unsound and should be rejected.[578]

While Ms. Uzenski was unsure during cross examination of the alternate forms of communication DTE uses to communicate with customers who choose not to receive a paper bill, her explanation is reasonable that DTE needs to use a variety of communication channels to present information to customers. Also, DTE did go through the exercise of sorting allowable categories of advertising expense from advertising categories that are not allowable,[579] and since there is no doubt the expenditures were made in the historical test year, this PFD recommends that the Commission allow the advertising expense. Nonetheless, the Commission should expect DTE to have a clear plan for communicating with customers who do not receive paper bills without relying on television or radio announcements.

11. Pension and Benefits (Exhibit A-10, Schedule C5, line 10)

a. Staff

Staff made three adjustments to expenses in this category. Mr. Welke explained that Staff's $46,000 adjustment was based on Staff's use of 2015 rather than 2014 historical expenses, adjusted to the projected test year using Staff's inflation factors.[580] In its initial brief, DTE adopted this adjustment, so this PFD considers it resolved.[581]

Mr. Welke also testified that Staff made an adjustment for accrued vacation expense because DTE's 2014 accrual was inconsistent with the accruals made in 2012, 2013 and 2015. He testified that Staff instead used a four-year average, resulting in a

[578] See DTE reply brief, page 60-61.
[579] See Uzenski, 4 Tr 799-800.
[580] See 5 Tr 1577.
[581] See DTE brief, page 10.

$1.9 million reduction in projected vacation expense.[582] In its initial brief, DTE adopted this adjustment, so this PFD considers it resolved.[583]

The third adjustment Staff made was to eliminate the projected SRP expense. Mr. Welke testified that Staff removed the projected SRP expense because it is a perquisite for highly compensated employees, and the Commission has removed this expense in prior cases.[584] Mr. Wuepper testified in support of this expense in his direct testimony asserting that in previous cases excluding this expense, Case Nos. U-17767, U-16472, and U-15244, the Commission had also excluded other expenses of which the SRP expenses were only one component.[585] He took issue with the Commission's decisions in those cases, contending the Commission should not have imposed a net customer benefit standard. He testified that the SRP "is merely a means to provide the same benefits to employees that earn more than the prescribed [Internal Revenue Code] limitations."[586] This PFD finds that the Commission has repeated resolved this issue, and DTE has provided no basis for the Commissionto reconsider its earlier decision regarding these non-qualified benefits.

b. Attorney General (Active employee health care)

The Attorney General takes issue with DTE's 7.5% projected increase in employee healthcare costs as shown in Schedule C5.9 of Exhibit A-10. Mr. Wuepper initially testified:

> An annual cost trend factor of 7.5% for 2015 through 2017 was applied to 2014 expense. This escalation assumption is consistent with the health

---

582 See 5 Tr 1577-1578.
583 See DTE brief, page 10.
584 See 5 Tr 1578.
585 See 4 Tr 926-927.
586 See 4 Tr 927-928.

> care escalation assumptions used by Aon Hewitt in developing the OPEB costs for retirees less than 65 years old.[587]

Mr. Coppola took issue with this projection:

> First of all, using an assumed cost factor for retirees to project active employee healthcare expenses is not appropriate. It is a known fact that health care costs are typically higher for older employees and retirees. Second, I asked the Company to provide any available studies supporting the 7.5% inflation factor. The Company refused to provide this same information in DTE Gas's rate case on the basis that it is proprietary material of Aon Hewitt. Therefore, the rate cannot be validated 1 and is unsupported. Third and more importantly, the Company's actual experience over recent years tells a different story. Active employee health care costs are down slightly over the past three years and up approximately 2.0% to 2.5% annually over the four-year period ending in 2015. Exhibit AG-12 includes the historical data provided by the Company.
>
> As such, I am setting the projected test period expense level for employee healthcare at $56.8 million using the actual recent 2.5% rate of increase. This is a reduction of $6.1 million to healthcare costs forecasted by the Company.[588]

In his rebuttal testimony, Mr. Wuepper did not deny that DTE refused to provide the Aon Hewitt study to the Attorney General, testifying as follows:

> While Witness Coppola states that the Company *refused* to provide any available studies from Aon Hewitt supporting the 7.5% assumption, it would be more accurate to state that the Company was *unable* to provide the underlying support. In fact, the method used by Aon Hewitt in developing the annual healthcare escalation assumption was described in my Direct Testimony, but the specific underlying analysis was developed and is owned by Aon Hewitt.[589]

His rebuttal testimony then cited some other publically available sources with health care cost escalation rates in the range of 6.5% to 10%, and identified certain types of expenses that he was concerned about, including drug costs, because:

> [T]he number of brand name drug patents scheduled to expire in 2016 and beyond is significantly lower than the recent past resulting in an increased

[587] See 4 Tr 922-923.
[588] See 6 Tr 1794-1795.
[589] See 4 Tr 979.

price per unit for brand name drugs. Second, high priced specialty drugs are becoming an increasingly significant portion of the total prescription drug usage. Approximately half of the drugs approved by the United States Food and Drug Administration (FDA) in 2015 were specialty drugs, the highest level over the last 18 years. Included within the specialty drug category is the increasing treatment for Hepatitis C, which can cost from $80,000 to $100,000 annually per patient. Third, the FDA is allowing more specialty drugs to be accorded fast track clinical trials and/or FDA review, which is increasing the number of specialty drugs coming to market.[590]

In its brief, DTE cites Mr. Wuepper's testimony and argues that there is no sound basis to conclude that the company's future active healthcare costs will increase "by any less than the 7.5% forecasted by the Company's benefit consultant, Aon Hewitt."[591]

In his brief, the Attorney General argues that Mr. Coppola's adjustment based on the recent rate of increase should be adopted:

First, using an assumed cost factor for retirees to project active employee healthcare expenses is not appropriate. (Tr 1794.) Second, is the fact that DTE refused to provide the studies supporting the 7.5% inflation factor on the grounds that it was proprietary material of Aon Hewitt. (Tr 1794-1795.) Accordingly, DTE's 7.5% inflation cannot be verified and is unsupported in the record. (Tr 1795.) Third, DTE's actual experience over the recent years demonstrates that active employee health care costs are down slightly over the past three years and up approximately 2.0% to 2.5% annually over the four-year period ending in 2015. (Tr 1795.) Exhibit AG-12 shows this historical data provided by the Company. Accordingly, Mr. Coppola set the projected test period expense level for employee healthcare at $56.8 million using the actual recent 2.5% rate of increase. (Tr 1795.)

The Attorney General also addressed Mr. Wuepper's rebuttal testimony in his brief:

On rebuttal, DTE witness Jeffrey Wuepper admitted that the Company did not and could not provide any available studies from Aon Hewitt supporting the 7.5% assumption. (Tr 979.) Mr. Wuepper, however, conveniently mentions in rebuttal that there are public domain studies that support Aon Hewitt's but conveniently fails to attach them to his rebuttal testimony, thus failing to provide competent evidence in the record to support DTE's burden. (Tr 979.) Mr. Wuepper then argued that DTE's last three years of active healthcare expenses is not a reliable indicator of

[590] See 4 Tr 990.
[591] See DTE brief, page 81.

> future active healthcare expenses but only supports that argument with the claim that healthcare expenses can change erratically based on the actual mix of medical care provided and the number of plan participants. (Tr 981.) The only actual support for this erratic variable was an example of a 2013 health care change. (Tr 982-983.) Of course, Mr. Wuepper failed to present any such change for the test year other than claiming that healthcare expense may change erratically.
>
> Instead of relying on studies that the Company failed to provide in the record for any party to review for their accuracy, the better evidence for the Commission to rely upon is the Company's actual historical numbers of healthcare costs. The net result of removing the Company's inflation adjustment to all the benefit categories and allowing it to recover 2.5% inflation on healthcare costs is a reduction of $6.2 million. (Tr 1795.) Accordingly, the Commission should adopt the Attorney General's adjustment in this area. Attorney General brief, pages 23-24.

In its reply brief, DTE did not address the Attorney General's argument that it failed to provide the study:

> AG witness Mr. Coppola proposed a 2.5% annual escalation rate purportedly based on a simple three-year average of increases in the Company's active healthcare costs for 2012 through 2014 (6T 1795). Mr. Coppola's methodology is unreliable because the Company is self-insured for the majority of its healthcare costs. DTE Electric's active healthcare costs are subject to annual variability depending on the level and mix of medical services received by employees and their dependents, and the price of those services. Active healthcare costs have a predictable long-term trend, but short-term volatility. Therefore, the 7.5% projected trend is a more reliable predictor of future expenses than Mr. Coppola's proposed short-term average (4T 981-82).
>
> AG witness Mr. Coppola's focus on short-term results is also misleading because the Company has reduced its healthcare costs through aggressive plan-design enhancements and improvements in the cost effectiveness of delivering benefits to its employees. The Company is proud of its results, but these efforts tend to produce the most savings when they are implemented. The lower costs provide a lower base for future cost increases, and then costs resume increasing at the normal escalation rate. There is also a limit to the plan-design changes that can be implemented, and a risk that active healthcare costs could increase by more than 7.5% based on new government regulations, such as the new EEOC regulations discussed above (4T 982-83).[592]

[592] See DTE reply brief, pages 65-66.

This PFD finds that Mr. Coppola's recommended $6 million adjustment should be adopted. As quoted above, DTE has acknowledged that it relied on the Aon Hewitt study in making its benefit cost projections. DTE had the opportunity to provide the report to support its projected health care cost escalation, and chose not to.[593] Mr. Wuepper's claim that the study is proprietary is unavailing, when DTE contracted with Aon Hewitt, Aon Hewitt publishes other information, and the ALJ entered a protective order in this case that would have prohibited the Attorney General and Mr. Coppola from using the report for any other reason than to attempt to verify DTE's claims in this case.

Mr. Wuepper's rebuttal testimony is also not the time for DTE to try to present an alternative justification for its health care numbers. Moreover, Mr. Wuepper's reliance on generic health data is contradicted by Mr. Wuepper's own testimony that its annual healthcare costs are "highly dependent on the level and mix of employee and dependent usage of medical related services and prices paid for healthcare in each year," and that "year-to-year variations in healthcare expense can be impacted by the degree its employees and/or dependents receive a disproportionately high or low level of high cost medical procedures. . ."[594] It is also contradicted by Mr. Wuepper's Exhibit A-32, Schedule V1, which shows varying rates of change for the different age groups shown there. Mr. Coppola's reliance on recent experience is a more appropriate and credible basis for the projection in view of DTE's refusal to provide the Aon Hewitt study.

---

[593] See, e.g., December 20, 2011 order in Case No. U-16582, pages 14-16, and see December 19, 2013 order in Case No. U-17302, pages 2-3.
[594] See 4 Tr 981-982.

12. AMI Savings

Mr. Sparks testified that costs savings in meter reading expenses are reflected in the historical (2014) expenses used as the starting point for DTE's projections, with additional savings forecast by Mr. Sitkauskas.[595] Mr. Sitkauskas presented DTE's O&M expense projections. The Attorney General recommended an increase of $1.1 million in projected savings. Mr. Coppola testified:

> Mr. Sitkauskas in Exhibit A-10, Schedule C5.13 shows AMI savings of $13.9 million. However, he has excluded any savings from lower Uncollectible Accounts costs from this exhibit even though such savings are set forth in his more detailed exhibit A-18. Exhibit AG-10 shows the determination of this savings based on the information provided by Mr. Sitkauskas in Exhibit A-18. The result is an increase in AMI Savings from $13.8 million to $14.9 million. I recommend that the Commission recognize this higher savings of $1.1 million in setting customer rates in this rate case.[596]

In its reply brief, DTE argues that this adjustment would be double-counting:

> The AG's miscounting (or double-counting) suggestion should be rejected because it is based on a misunderstanding and misapplication of DTE Electric's cost-benefit analysis as set forth in Exhibit A-18. Uncollectible costs are already accounted for otherwise, and should be set in accordance with Staff's proposal.[597]

Although the Attorney General's proposed adjustment did not receive much attention in this case, this PFD recommends that the Commission defer greater scrutiny of the savings projections associated with AMI to DTE's next rate case, after Staff and the parties have had an opportunity to review DTE's reporting, and can better evaluate whether the amount savings reflected in the uncollectible expense projection average is consistent with the costs expected going forward.

[595] See 4 Tr 1013.
[596] See 6 Tr 1796.
[597] See DTE reply brief, pages 47-48.

D. Other Expenses

This section includes a discussion of depreciation and amortization expense, as well as taxes and AFUDC.

1. Depreciation and Amortization Expense

a. *Staff Correction*

Mr. Gerken corrected DTE depreciation rates, including its computation of depreciation expense.[598] In its brief, DTE adopts Staff's corrected figures. This PFD considers this issue resolved.

b. *Capital Expenses*

Mr. Gerken also adjusted DTE's depreciation expense to reflect the reductions in capital expenditures Staff recommended as part of its direct case. These adjustments were not controversial. The depreciation expense included in the revenue requirement in this case should match the capital projections adopted by the Commission in its final order.

c. COL Amortization

As discussed above, in Case No. U-17767, the Commission authorized a twenty-year amortization of $101.9 million, based on its finding that DTE had expended that amount. Consistent with the discussion in section IV above, this PFD has concluded that the Commission's order in that case specifies the final rate treatment for COL expenses until DTE decides to build the plant or decides to sell the license. Thus, the appropriate amortization expense to include in rates is one-twentieth of the $101.9 million amount, as previously authorized.

[598] See 5 Tr 1480-1481

2. Property tax

Mr. Heaphy presented direct testimony in support of DTE's projected tax expenses including the "property and other" tax category shown in Exhibit A-10, Schedule C7, page 1. Property tax is the largest element of this expense and is developed further in Schedule C7, page 2. Mr. Heaphy testified that the increase in the property tax expense was attributable to capital additions forecast by Mr. Warren, Mr. Milo, Mr. Whitman, Mr. Colonnello, Mr. Sitkauskas, Ms. Dimitry, Mr. Sparks, and Ms. Uzenski.[599]

Mr. Welke explained Staff's adjustment to property and other taxes:

> From 2011 through 2015, the Company's Combined Average Growth Rate (Property & Other Tax Expense has been 3.61%. (Exhibit S-7, Line 3). Staff used that CAGR of 3.61% and applied it to the Company's 2015 actual Property & Other Tax Expense of $274,501,000. (Exhibit S-7, Line 1, Column (j.)). Using that methodology, Staff's projected Property & Other Tax Expense is $290,401,000, which is $23,903,000 lower than the Company's projection of $314,304,000. (Exhibit S-7, Line 5).[600]

He testified that DTE's projection is significantly out of line with actual historical experience, as shown in Exhibit S-7. He testified that using historical data, DTE's projection method would have resulted in a significant over projection for 2014 of $3 million, while Staff's method would have resulted in a small under projection of $.655 million.[601]

In his rebuttal testimony, Mr. Heaphy objected to Staff's adjustment on the basis that Staff's use of a compound average growth rate incorrectly assumes a uniform increase in property taxes.[602] He presented Exhibit A-33 to show the variability in

[599] See 4 Tr 993-994.
[600] See 5 Tr 1583.
[601] See 5 Tr 1584.
[602] See 4 Tr 999-1001.

property taxes from year to year from 2011 to 2015. He also testified that property tax expenses have been significantly impacted by the nature of DTE's capital additions:

> Witness Welke's CAGR methodology does not accurately forecast property tax expense because it does not take into account the significant increase in taxable assessed value resulting from fewer tax exempt, pollution control assets being placed in service in the forecasted years. Furthermore, the CAGR calculated by Witness Welke, assumes capital additions, and the type of additions, will be the same in the future as in the past which is not correct. Using a CAGR percentage to project property tax expense in the forecast period would significantly understate property tax expense because it erroneously assumes the Company will incur the same level of tax exempt asset additions (i.e., pollution control assets), as the prior year.[603]

He testified that since 2008 DTE has incurred roughly $2 billion in capital expenditures that are tax-exempt pollution control assets, and is now forecasting only $130 million of capital expenditures that qualify as tax-exempt pollution control assets.[604]

In its brief, Staff responded to Mr. Heaphy's rebuttal testimony, arguing that the average change in the property and other tax expenses in Exhibit A-24 is 3.63%, which is close to Staff's projected 3.61%: "This is in stark contrast to the company's unreasonable assumed growth rate of 8.621% through the projected test-period."[605] Staff argues that its calculation is reasonable because it relies on actual property tax experience.

DTE's brief parallels Mr. Heaphy's testimony. DTE argues that Staff's use of a compound annual growth rate does not account for the factors that drive the increase in property taxes.

---

[603] See 4 Tr 1001-1002.
[604] See 4 Tr 1002, citing Exhibit A-9, Schedule B6.1.
[605] See Staff brief, page 79.

In its reply brief, Staff suggests as an alternative using the highest year-to-year increase. Staff argues that this 6.635% growth rate is still lower than the 8.621% assumed growth rate reflected in Mr. Heaphy's calculation.[606]

This PFD finds that DTE has not supported its property and other tax calculation because it has not supported its projected increase in property taxes. Mr. Heaphy's testimony and calculation in Schedule C7 of Exhibit A-10 is unaccompanied by any explanation how the $3.2 billion in projected capital expenditures presented in DTE's filing translate to the $965 million in additions offset by $244 million in retirements used as the basis to calculated incremental taxable value. Importantly, it does not provide any insight how that calculation should be modified if the Commission does not accept all of Mr. Warren's, Mr. Whitman's, Mr. Colonnello's, Ms. Dimitry's, or Ms. Uzenski's capital expense projections. Note too that it relies on a composite millage rate in line 25 that is not explained, as well as composite multipliers used to determine the true cash value in lines 16 and 17. Thus, contrary to DTE's argument, DTE's tax projection does not account for the factors that cause property tax expenses.

On this basis, it is reasonable for Staff to look to historical data to determine an appropriate expense allowance for property and other taxes. Mr. Welke's original recommendation to use the historical rate of increase of 3.6% is reasonable because it relies on historical average rates of increase. Staff's alternative recommendation to use the highest historical rate of increase of 6.6% is used in the rate calculations in this PFD to reflect Staff's efforts at compromise. The Commission should also require DTE to provide more transparency in its calculation of property taxes in future rate cases.

[606] See Staff reply brief, page 24.

3. <u>FIT</u>

Mr. Nichols testified that Staff adjusted projected Federal Income Tax expense to be consistent with Staff's projected adjusted net operating income.

4. <u>State & Local Tax</u>

Likewise, Mr. Nichols testified that Staff adjusted State and local tax expense to be consistent with Staff's projected income.

The RCG also raised an issue regarding the treatment of the increase in the City of Detroit's taxes in 2012. In Case No. U-17767, the Commission accepted DTE's tax normalization accounting according to the Commission's order in Case No. U-16894. The RCG asks that the Commission reconsider its position on this issue. Mr. Crandall testified that the Commission should not continue to allow DTE to recover, through amortization, costs associated with an increase in the Detroit municipal tax rate in 2012.

Mr. Heaphy responded in rebuttal, explaining the company's compliance with prior Commission orders:

> The February 15, 2012 order in Case No. U-16864 states regulated utilities are required to apply the Commission's policy for deferral accounting and full normalization ratemaking to the recent state and federal tax law changes, as delineated in the February 8, 1993 order in Case No. U-10083, over a period reasonably related to the reversal of the underlying book-tax basis differences. Accordingly, the Company began amortizing the regulatory asset in 2012 and did not seek recovery of the amortization for 2012 through June 30, 2015 in the Company's last rate case, Case No. U-17767. Therefore, the Company is not seeking to retroactively recover out-of-period taxes in this proceeding. Rather, the Company is merely complying with the Commission orders in Case Nos. U-10083 and 16864 to recognize the taxes arising from the City of Detroit tax rate increase on deferred taxes.[607]

As Mr. Healphy explained and as DTE argues in its brief, the Commission resolved this issue in Case No. U-17767 in accordance with the Commission's February 15, 2012

[607] See 4 Tr 1003-1004.

order in Case No. U-16868, and the RCG has not provided any basis for the Commission to reconsider its decision.

5. AFUDC

Mr. Nichols testified that Staff did not identify any concerns with DTE's projected AFUDC amount of $31,953,000, as shown in Exhibit S-3, Schedule C1, line 12. Nonetheless, for the reasons stated above in connection with the discussion of CWIP, this PFD recommends that the Commission require greater detail regarding CWIP and offsetting AFUDC in future filings.

6. Other

Mr. Nichols also testified that Staff did not identify any concerns with DTE's projected other income of $3.5 million, as shown in Exhibit S-3, Schedule C1, line 13.

E. Adjusted Net Operating Income Summary

Based on the foregoing discussion, this PFD estimates an adjusted net operating income of $671,955,000 as shown on Attachment C.

VII.

REVENUE DEFICIENCY SUMMARY

Based on the rate base, cost of capital, and adjusted net operating income as presented above, DTEE's revenue deficiency for the projected test year is estimated to be $187 million, as shown in Appendix A, attached.

IX.

COST OF SERVICE AND RATE DESIGN

In contrast to some cases, there are relatively few disputes regarding the cost of service allocations and rate design. Cost allocation issues are discussed in section A below; rate design and tariff issues are discussed in section B.

A. Cost of Service Allocations

As discussed in this section, the parties still dispute the production cost allocation and the allocation of uncollectible expense. DTE's cost study in support of its proposed monthly customer charges is also discussed. Also, the concern expressed by the Detroit Public Schools is addressed in this section.

1. Production Cost Allocation

As it did in Case No. U-17767, DTE recommends that the Commission revise the production cost allocation method from the current method, which gives a 75% weighting to demand on four coincident peak days (4CP) and a 25% weighting to total annual energy use, abbreviated as the 4CP 75-0-25 method or simply the 4CP 75-25 method, to an allocation based entirely (100%) on demand on the four coincident peak days, abbreviated 4CP 100. ABATE and Kroger agree with DTE while Staff, the Attorney General, and MEC/SC/NRDC oppose the request.

Mr. Stanczak testified for DTE on this issue:

> The 4CP 75-0-25 allocation method does not fully align cost allocation with cost causation. Therefore, customer classes which use more energy in relation to their demand are allocated more fixed costs, regardless of the demand they place on the system and the capacity this demand requires. Under the 4CP 75-0-25 method, if a customer class increases its energy usage without increasing system demand, thus using the system

more efficiently due to an increase in load factor, this class would see an increase in the allocation of capacity related costs.[608]

He testified that the 4CP 100 method “more appropriately aligns cost allocation with cost causation”:

> This is of particular importance given the need for new production capacity and the investment necessary to retrofit existing generation to meet environmental standards. That is, because the 4CP 100-0-0 methodology allocates fixed production costs entirely on a demand basis, rather than a combined demand and energy basis, it appropriately allocates generation capacity costs to customers based on the load characteristics that drive cost.[609]

Mr. Stanczak characterized the Commission’s prior orders adopting the 4CP 75-25 allocation method as an “incremental improvement to better recognize the value of production capacity.”[610] He also discussed “emerging dynamics” that DTE had presented to the Commission in Case Nos. U-17689 and U-17767:

> In Case Nos. U-17689 and U-17767, the Company identified several emerging issues that necessitated evaluation of the Company’s production cost allocation methodology, including: 1) the completion of rate deskewing; 2) an anticipated generation resource shortfall in Midcontinent Independent System Operator (MISO) Zone 7 (the lower peninsula of Michigan); and 3) existing and proposed environmental regulations relative to coal-fired power plants.[611]

He testified that these concerns are “still applicable” and “perhaps even more so now than when initially presented in Case No. U-17767.”[612] Although acknowledging uncertainty regarding the impact of the Clean Power Plan and other environmental regulations on either DTE or the marketplace in the near term, he testified:

> Specifically, in MISO’s report titled “2015 OMS Survey Results” dated June 2015, MISO projects a 1.2 to 1.3 GW Zone 7 Resource Requirement

---

[608] See 4 Tr 1093.
[609] See 4 Tr 1097.
[610] See 4 Tr 1093.
[611] See 4 Tr 1093-1094.
[612] See 4 Tr 1094.

shortfall in the 2016-2017 plan year, with a regional shortfall potentially occurring as early as 2020. In addition, the United States Environmental Protection Agency (EPA) recently issued its final rule on the Clean Power Plan which will require Michigan to lower its CO2 emissions rate significantly by 2030. The Clean Power Plan, in combination with other environmental regulations, could have a significant impact on electric reliability by potentially accelerating retirements of existing coal-fired power plants both for the Company and for other utilities in the region.[613]

Mr. Stanczak also cited Staff's July 9, 2015 report in Case No. U17751. In addition, he testified that DTE has already begun to modify its generation profile to focus more on peak demand, citing the acquisition of the Renaissance and Dean power plants, the retirement of Trenton Channel Units 7A and 8, and DTE's tentative plans to retire other plants and add new gas-fired plants and renewable energy. In Mr. Stanczak's opinion it is appropriate to "transition" to a 4CP 100 production cost allocation method, notwithstanding the Commission's prior orders rejecting this method:

> A large shift from a long standing regulatory practice can create significant impacts on customers. As I described earlier, prior to Case No. U-17689, the Commission had authorized a 12CP 50-25-25 production cost allocation for recent DTE Electric rate cases. Therefore, the change from a 12CP 50-25-25 to a 4CP 75-0-25 cost allocation methodology in Case No. U-17689 was an important first step towards appropriately aligning cost allocation with cost causation. However, given the ongoing concerns regarding resource adequacy in both the State of Michigan and the region (as documented by both the MISO and MPSC Staff), now is the time to complete the gradual transition to a 4CP 100-0-0 production cost allocation which best recognizes the value of capacity.[614]

ABATE's witness Mr. Dauphinais also recommended the 4CP 100 allocation for production costs:

> DTE Electric must plan for and provide adequate generation capacity to meet the summer peak loads on its electric system. Therefore, it is the summer peaks that are causing DTE Electric to acquire generation capacity and the Company to incur additional production fixed costs.

[613] See 4 Tr 1094.
[614] See 4 Tr 1097.

> Therefore, the summer peaks should be used solely to allocate the fixed production costs.[615]

He presented Exhibit AB-20, with FERC Form 1 data, to show the monthly maximum peak demands on DTE's system over the last ten years.

Mr. Putnam agreed with the arithmetic that an allocation of a portion of fixed costs on an energy basis allocates more fixed costs to customer classes that use more energy in relation to demand, but he explained:

> [W]hile the Company argues this is an inappropriate alignment of cost allocation with cost causation, Staff views this as necessary to align cost allocation with cost causation. The choice in constructing and acquiring production assets is influenced both by the need to meet demand on the hottest day of the year and the need to meet energy requirements for all 8,760 hours of a year. Both demand and energy play a part in the acquisition of production assets, so both demand and energy should play a part in the allocation of those production asset costs. The challenge lies in determining a reasonable weighting for the demand and energy portions of the production allocator.[616]

Mr. Putnam testified that Staff reviewed the National Association of Regulatory Commissioners Electric Utility Cost Allocation Manual (NARUC Manual) to develop production allocators using many of the methods described in the manual. He presented a table ranking these methods as well as DTE's proposed modification in relationship to the current method. This chart shows that for every dollar allocated to the residential class under the current method, DTE's proposal would allocate $1.06, and for every dollar allocated to the primary class under the current method, DTE's proposal would allocate $0.92. The corresponding relative values are shown for eight other allocation methods.[617] From this table, Mr. Putnam concluded that the current method reasonably recognizes the value of capacity. Mr. Putnam views DTE's claims

[615] See 6 Tr 1963, also see 6 Tr 1962-1964.
[616] See 5 Tr 1343.
[617] See 5 Tr 1344.

that it is modifying its generation profile to focus more on peak demand as "evidence that energy might have been given too little weight in the prior case," making the current 75% demand, 25% energy weighting appear to be "even more reasonable."[618] Mr. Putnam also reviewed prior Commission decisions addressing the allocation of production costs, and testified that for the past 40 years, the Commission has always used at least a 25% weighting for energy costs.[619]

Mr. Coppola also addressed DTE's proposed revision of the production cost allocation method. Citing Commission decisions in Case Nos. U-17689, U-17767, and U-17735, he testified:

> [T]he Company once more is requesting that the Commission adopt its proposed 100/0/0 without presenting any new compelling evidence and simply re-hashing the same arguments it has made in previous cases. It seems that the Company can't accept no for answer.
>
> The Commission should again reject this latest attempt by the Company and direct the Company to refrain from presenting the same proposal in future rate cases unless it is able to present new, significant and compelling evidence which the Commission has not seen and evaluated previously.[620]

Mr. Sansoucy testified for MEC regarding the allocation of production costs.[621] He reviewed the Commission's recent orders on this issue, and he reviewed Mr. Lacey's and Mr. Stanczak's testimony in this docket. He took issue with any suggestion that DTE has presented new evidence or circumstances in support of its request that the Commission move to a 4CP 100 allocation formula.[622] Mr. Sansoucy presented four graphs and tables, Exhibits MEC-17 to MEC 20, each showing hourly

[618] See 5 Tr 1345.
[619] See 5Tr 1345-1346.
[620] See 6 Tr 1859.
[621] Only MEC takes a position on this issue, not SC or NRDC.
[622] See 5 Tr 1651-1653.

demand by customer class on four summer-month peak days. He testified that in these examples, commercial and industrial demand peaks during the early afternoon, while residential demand ramps up as customers come home in the evening and then ramps down after a few hours as they go to bed.[623] He testified that DTE is proposing to allocate 41.4% of the fixed costs of its entire production fleet based 100% on residential customer demand for these four evening hours, citing DTE's Exhibit A-13, Schedule F1.1, page 1. He further testified that DTE will meet this demand with lower-fixed-cost peaking resources.

Mr. Sansoucy testified that there are many recognized methods for allocating production costs, reviewing the NARUC Manual, which he presented as Exhibit MEC-21. He testified that the 4CP 100 method that DTE recommends is one of 13 "embedded cost" methods for allocating production costs, and testified that DTE should have explored methods that include an energy weighting: "Including an energy weighting would have more accurately portrayed the complexity of cost causation than the singular focus on demand described by DTE witnesses Stanczak and Lacey."[624] He quoted the following passage from the NARUC Manual:

> Cost causation is a phrase referring to an attempt to determine what, or who, is causing costs to be incurred by the utility. For the generation function, cost causation attempts to determine what influences a utility's production plant investment decisions. Cost causation considers: (1) that utilities add capacity to meet critical system planning reliability criteria such as loss of load probability, loss of load hour, reserve margin, or expected unserved energy; and (2) that the utility's energy load or load duration curve is a major indicator of the type of plant needed. The type of plant installed determines the cost of the additional capacity. This approach is well represented among the energy-weighting methods of cost allocation.[625]

[623] See 5 Tr 1654.
[624] See 5 Tr 1655.
[625] See Exhibit MEC-21, pages 38-39.

And he quoted the following passage:

> There is evidence that energy loads are a major determinant of production plant costs. Thus, cost of service analysis may incorporate energy weighting into the treatment of production plant costs. One way to incorporate an energy weighting is to classify part of the utility's production plant costs as energy-related and to allocate those costs to classes on the basis of class energy consumption.[626]

Mr. Sansoucy testified that DTE should have considered the "Equivalent Peaker Method". He cited Mr. Stanczak's testimony contending that DTE's production cost allocation method should be changed due to the company's capacity needs. He testified that according to the NARUC Manual, the Equivalent Peaker Method is particularly appropriate for a utility that is acquiring generation to meet capacity reserve requirements:

> Equivalent peaker methods are based on generation expansion planning practices, which consider peak demand loads and energy loads separately in determining the need for additional generating capacity and the most cost-effective type of capacity to be added. They generally result in significant percentages (40 to 75 percent) of total production plant costs being classified as energy-related, with the results that energy unit costs are relatively high and the revenue responsibility of high load factor classes and customers is significantly greater than indicated by pure peak demand responsibility methods.
>
> The premises of this and other peaker methods are: (l) that increases in peak demand require the addition of peaking capacity only; and (2) that utilities incur the costs of more expensive intermediate and baseload units because of the additional energy loads they must serve. Thus, the cost of peaking capacity can properly be regarded as peak demand-related and classified as demand-related in the cost of service study. The difference between the utility's total cost for production plant and the cost of peaking capacity is caused by the energy loads to be served by the utility and is classified as energy-related in the cost of service study.[627]

Mr. Sansoucy cited DTE's acquisition of the Renaissance and Dean plans as examples of peaking resources with low fixed and high variable costs in comparison to

[626] See Exhibit MEC-21, page 49.
[627] See 5 Tr 1656; Exhibit MEC-21, pages 52-53.

a baseload unit, referencing Ms. Dimitry's testimony to this effect in Case No. U-17767, which he presented in his Exhibit MEC-22.[628] He also presented a spreadsheet in his Exhibit MEC-23 to illustrate this, making clear this is not a cost of service study. He recommended that the Commission allocate baseload generation using the 4CP 50-25-25 method, which he characterized as the "default" method under 2008 PA 286, and allocate peaking generation using the 4CP 100 method:

> According to the Equivalent Peaker Method, the fixed cost of baseload plant generation should include an allocation based on energy, because the incrementally higher fixed cost of that category of generation produces relatively lower energy costs, which provide value especially to higher load factor customers. Residential customers should bear an equitable share of the cost associated with peaking resources, but it is not consistent with cost causation to allocate the cost of baseload resources to them on the same percentage as the peaking resources used to meet peak demand. Therefore, it would be consistent with the Equivalent Peaker Method to allocate the fixed costs of peaking units using the 4CP 100-0-0 method, if and only if the fixed costs of baseload units were allocated using the 4CP 50-25-25 method that represents the default method under Act 169.[629]

He also specifically addressed the Ludington plant, recommending that it be treated essentially as a baseload plant, with new generation evaluated at the time of acquisition to determine the best allocation method. He recommended that DTE be directed to file a revised cost of service study and rate design consistent with this method.

Mr. Dauphinais also presented rebuttal testimony on this issue, reiterating his view that 4CP 100 reflects cost causation and sends proper price signals. He testified that DTE's summer peak demand is the driving force for adding additional generation, and cited the Commission's July 22, 2016 order in Case No. U-17992 expressing concerns regarding adequate capacity in the State.[630]

---

[628] See 5 Tr 1657.
[629] See 5 Tr 1659.
[630] See 6 Tr 2018-2020.

MEC also takes issue with DTE's reliance on the June 2015 MISO capacity shortfall estimate in its brief:

> Moreover, the record in this case does not support DTE's thrice-repeated argument that a potential resource shortfall in Zone 7 necessitates its proposed allocation methodology. In support of this argument, DTE relies on a June 2015 MISO report that DTE interprets as projecting a resource requirement shortfall in MISO Zone 7 in the 2016-2017 plan year. However, as Energy Michigan Witness Alexander J. Zakem testified, MISO has since updated that report with a survey undertaken in 2016. The 2016 survey documents an improvement in the outlook for MISO Zone 7 by 1.0 GW between the 2015 report and the 2016 report, with a deficit of only -0.3 GW. In addition, the 2016 report shows substantial planned new generation in various stages of development, and confirms that only a small fraction of this new generation under development would have to go into service to eliminate the deficits in the 2015 report. For Zone 7 deficits, according to MISO, the surplus/deficit situation has improved steadily and significantly, even excluding new resources under development. As such, the Commission should reject DTE's request to revisit the production cost allocation methodology.[631]

MEC reviews the recommendations against use the minimum-size method included in the internal DTE study that Mr. Lacey relied on, including the following:

> The report considers how to allocate distribution investment to the customer and demand components using the minimum system method and the zero intercept method, both of which are also discussed in the NARUC manual. It generates examples to demonstrate how – using the same data – the two methods result in very different allocations between customer and demand. After considering the results of the methods, the report concludes:
>
> There is an old adage that says 'if a person commits a crime, we may know he is guilty but we do not know the extent of his guilt because we do not understand or cannot see all the inner workings of the mind.' We have the same problem in the classification of the various distribution accounts into customer and demand components. We know that there is a relationship but we do not know the extent of that relationship.[632]

[631] See MEC brief, page 50 (footnotes omitted).
[632] See MEC brief, page 63, quoting Exhibit MEC-41, also KC-2.

In its briefs, DTE emphasizes Mr. Stanczak's testimony, also citing ABATE's testimony at 6 Tr 2018-2021.[633] Kroger supported DTE's position.[634] ABATE argued the 4CP 100 method reflects cost causation and sends proper price signals, which can "cause [customers] to act to reduce their demand and to avoid new generation capacity."[635] ABATE further argues:

> The fixed production cost allocation methodology supported by the Staff is no longer valid in that DTE is no longer building power plants that involve higher capital cost to obtain lower fuel cost. In the past, it made sense to invest in central station coal-fired plants to achieve lower cost of electricity based on lower costs for coal. That paradigm has changed completely. The concept that supported that, known as 'capital substitution,' was previously thought of as a basis to invest in capital-intensive generation plants that had relatively low fuel costs to operate. All new generation being obtained by DTE consists of single- or combined-cycle natural gasfired units. And DTE is in the process of retiring its coal fleet.103 As such, there is no longer a justification for allocating 25% fixed production costs to fuel, which is what the 4CP (100-0-25) allocation methodology does.[636]

Staff and MEC take issue with ABATE's analysis in their reply briefs.[637] MEC argues that the Commission expressly rejected ABATE's argument regarding price signals in Case No. U-17689, explaining: "merely raising the overall cost of electricity does not necessarily encourage customers to shift their usage from peak times, although total energy consumption may decrease."[638]

> Staff argues that ABATE's claim that DTE is retiring its coal plants and no longer building high capital-cost plants with low fuel costs is not based on record evidence. Staff notes that ABATE's cross-examination of Mr. Bloch regarding the retirement of 3,300 MW of coal plants showed that DTE would not retire those plants until 2023.[639] Staff also argues that ABATE's claims do not include an analysis of the capital cost or variable production

[633] See DTE brief, pages 114-118; DTE reply brief, pages 101-103.
[634] See Kroger brief, page 5.
[635] See ABATE brief, pages 23-26, page 24.
[636] See ABATE brief, pages 25-26.
[637] See Staff reply, pages 25-26; MEC reply, pages 5-6.
[638] See June 15, 2016 order, Case No. U-17689, page 21.
[639] See 3 Tr 506.

costs of the different types of gas-fired plants that DTE may build, and do not contradict the important role that both demand and energy considerations play in the acquisition of production assets.

This PFD recommends that the Commission reject the request to revise the production cost allocation method to 4CP 100. Nothing in the Commission's prior orders suggested that in adopting the 4CP 75-25 method, the Commission acknowledged it was "transitioning" to a 4CP 100 production cost allocation. As Mr. Sansoucy's testimony indicates, DTE has provided no new information to cause the Commission to reconsider its earlier determination that an energy weighting is an important component of a production cost allocation method. While Mr. Stanczak cited DTE's acquisition of the Renaissance and Dean gas-fired plants and an expected MISO capacity shortfall, DTE's acquisition of the gas-fired plants was known in the last rate case,[640] and DTE also relied on MISO's estimated capacity shortfall in that case.[641] The claim made in ABATE's brief, quoted above, to the effect that reliance on baseload power plants has "changed completely", lacks supporting evidence on this record.

Instead, Mr. Putnam's testimony is persuasive that the current energy allocator is reasonable under the present circumstances, and consistent both with the Commission's recent orders and with its longstanding recognition of the importance of considering energy consumption as well as peak demand in allocating production costs. Mr. Sansoucy's testimony is persuasive that moving forward, as DTE revises its generation mix to meet capacity needs including capacity reserve requirements, the Equivalent Peaker method is the logical transition. As he testified and as supported by

---

[640] See December 11, 2015 order in Case No. U-17767, page 2.
[641] See December 11, 2015 order in case No. U-17767, page 112. ("DTE Electric contends that information from MISO, released after the June 15 order, and the Commission's determination in the July 23, 2015 order in Case No. U-17751, both of which predict capacity shortfalls in the coming years, make it essential to assign production costs to customers whose load characteristics drive those costs.")

Exhibit MEC-21, the NARUC manual recommends this method under such circumstances, and by looking at the characteristics of the generation resources, a more analytical result can be achieved to match costs with cost-causation. Notably, DTE did not provide rebuttal testimony on this topic and Mr. Dauphinais's generic rebuttal statements did not address either Mr. Putnam's or Mr. Sansoucy's more thoughtful and considerate testimony. From this testimony, it is clear that the equivalent peaker method would take into consideration the nature of additional capacity, whether designed primarily to meet summer peak demand or otherwise. Therefore, this PFD recommends that the Commission reject DTE's renewed request to adopt a 4CP 100 allocation method, and continue to use the 4CP 75-25 method adopted less than a year and a half ago in Case No. U-17689. In addition, this PFD recommends that the Commission direct any party proposing to change the production cost allocation method to include in its evidentiary presentation an analysis using the equivalent peaker method or an approximation for comparison purposes, since this is the only method on this record that appears capable of shedding additional light on what are becoming merely repetitive arguments.

2. Uncollectible Accounts Expense

In Case Nos. U-17689 and U-17767 the Commission adopted a revised allocation for uncollectible expense, using historical uncollectible expense by class. Mr. Putnam testified that Staff recommends revising the allocation method to an allocation based on total rates, fuel and purchased power costs. He testified:

> It is Staff's position that [Uncollectible Accounts Expenses] are a general cost of performing business as a utility. As such, they should be allocated based upon an overall allocation scheme. Therefore, Staff has chosen an allocator based on the cost to serve the rate classes. Cost of service

> including fuel and purchased power represents the amounts that will be owed to the Company by customers as a result of rates set in this case, and is, by definition, a cost-based approach.[642]

Mr. Putnam testified that Staff has also proposed this method in DTE's pending gas rate case, Case No. U-17999. While in Case No. U-17767 the Commission rejected Staff's request to revise the allocation method it had just recently established in Case No. U-17689, here Staff has presented a different allocation method than the method rejected in those two prior cases, which used the class revenue requirement. In its brief, Staff also quotes the NARUC Manual to show that its method as well as the current method are acceptable. And, Staff emphasizes its view that uncollectible expenses are not directly related to any class.[643]

Mr. Lacey testified in rebuttal, asserting that Staff has presented no evidence that using cost of service plus the cost of fuel and purchased power is correlated to the class that causes uncollectibles:

> One test to assess the suitability of a proposed method of allocating uncollectible expense is how well it reflects cost causation. Using cost of service plus cost of fuel and purchased power as the basis for allocating uncollectible expense would imply that a classes' revenue requirement correlate with the classes' failure to pay their bills. In 2014, the residential rate class was responsible for 83.75% of net write-offs but only 47.35% of the revenue requirement. (See Exhibit A-36, Schedule Z3). Therefore, the Company's Commission approved method of allocating uncollectible expense based on net write-offs better reflects cost causation than does the Staff's proposed method.[644]

In its reply brief, MEC/SC/NRDC indicate that they agree with Staff that the Commission should revisit this issue. In the context of objecting to Mr. Lacey's treatment of uncollectible expense as a marginal cost of customer attachment in his

[642] See 5 Tr 1349.
[643] See Staff brief, pages 86-85.
[644] See 3 Tr 442-443.

customer cost analysis, Mr. Jester discussed cost causation in the context of uncollectible expense:

> Uncollectibles are caused by customers who don't pay their bills. Unfortunately, that means that the cost of uncollectibles cannot be recovered based on cost causation. Historically, these costs were treated by DTE as "overhead costs" allocated to all customer classes proportional to revenue. In its order of December 11, 2015 in U-17767 the Commission approved DTE's proposal to allocate these costs to customer classes based on the customer class of the non-paying customers. However, in that case the parties and the Commission did not address the allocation of uncollectibles within the cost of service study and in rate design.[645]

In its reply brief, ABATE argues that the Commission should continue the same methodology adopted in Case No. U-17767 "since it best allocates those expenses to the classes which cause those expenses."[646]

While the Commission also revisited the proper allocation of uncollectible expense in Case Nos. U-17689 and U-17767 and concluded that uncollectible expense should be allocated based on class contribution to write-offs, now net write-offs, there was no theoretical explanation or analysis of cost causation such as exists for the production cost allocation issue. Instead, the Commission essentially defaulted to a method identified in the NARUC Manual, viewing the ability to assign costs to each class based on historical write-offs as a form of cost causation. In doing so, the Commission found that:

> A principle of cost allocation is that costs that are directly attributable to a particular customer or class of customer should be directly assigned to that customer or class. As recognized by the NARUC Manual, Exhibit MEC-18, uncollectibles expense is an example of a customer-related cost that may be directly assigned to the class that is responsible. The Manual, p. 103, states that for Customer Account Expenses, Accounts 901-905:

---

[645] See 5 Tr 1608
[646] See ABATE reply brief, page 11.

> These accounts are generally classified as customer-related. The exception may be Account 904, Uncollectible Accounts, which may be directly assigned to customer classes.[647]

At the same time, the Commission stated:

> The alternative, which DTE Electric currently uses, is to treat uncollectibles expense as overhead and allocate these costs to customers without considering how different classes of customers are actually causing the costs.[648]

In a footnote, the Commission explained:

> The NARUC Manual also recognizes this approach in noting, that some analysts prefer to regard uncollectible accounts as a general cost of performing business by the utility and would classify and allocate these costs based upon an overall allocation scheme, such as class revenue responsibility.[649]

Thus, while this PFD finds Staff's analysis persuasive,[650] it is clear that the Commission had the opportunity to consider this analysis in that case less than 18 months ago. On that basis, this PFD recommends that the Commission decline to revisit this issue at this point in time, but indicate that it is open to further analyses of the consistency of the current allocator and of other potentially-explanatory allocators.

3. Detroit Public Schools Allocation Issue

The Detroit Public Schools argue in their brief that the cost allocations determining their rate have been highly variable in the recent rate cases. The Detroit Public Schools present a chart in their brief that shows the overall percentage revenue increase provided in each rate case beginning in 2011, with the percent changes for Rate D3.2 and Rate D6.2. This chart shows that after rate decreases in Case No.

[647] See Case No. U-17689, pages 26-27.
[648] See June 15, 2015 order in Case No. U-17689, page 27.
[649] See June 15, 2015 order in Case No. U-17689, page 27 at n7.
[650] Mr. Lacey's rebuttal testimony contends that Staff's method is deficient because Staff has not shown that the resulting allocation matches the class revenue allocation, although his analysis appears to use a 50-25-25 method of production cost allocation.

U-16472, and putting aside self-implementation increases, Rate D3.2 decreased 9.3% following the Commission's rate order in Case No. U-17767. It is now projected to increase on the order of 17%. Rate D6.2 increased following the Commission's order in Case No. U-17767 by 11.2%, and is now projected to increase approximately 13.5% to 15%.[651] DTE argues that no adjustment can be made in DPS's rates. Based on this record, this PFD agrees with DTE. Nonetheless, in future cases, the reason for significant changes in rates for certain rate schedules relative to class averages should be able to be investigated and evaluated.

4. Incentive Compensation (Allocation)

Mr. Zakem expressed a concern regarding the allocation of any incentive compensation costs authorized by the Commission. Reviewing DTE's Exhibit A-20, Schedules L1-L5, he characterized the dispute over cost recovery as a policy dispute that has been re-argued over many years. He expressed a concern that if incentive compensation is going to be included in rates and tied to utility performance, rate recovery should be allowed only in the rates of customers who are benefitted by the performance criteria. As discussed above, he objected to the financial measures on the basis that they benefit shareholders. Regarding cost allocation, he testified that DTE has not separated distribution service benefits from power supply service benefits. Citing lines 46-59 of Schedule L5, he testified that 5 of the 8 operating measures related directly to power plants, and the costs of those should not be passed on to choice customers.

[651] See Detroit Public Schools brief, page 5.

Mr. Lacey testified in rebuttal:

> As a matter of clarification, my response will address how the costs associated with incentive compensation (as opposed to benefits) are functionalized within the cost of service because *Witness Zakem's advocacy of functional separation seems to be focused on the costs included in the distribution rates paid by Electric Choice customers rather than the benefits enjoyed as a result of incentive compensation*. While it is true that Exhibit A-20, Schedule L5 does not undertake a functional separation of the costs associated with incentive compensation, the cost of service and subsequent rate design do just that. Incentive compensation costs are included in O&M expense by MPSC Uniform System of Account. Each such account is functionalized within the cost of service. As a result, costs functionalized as production-related are included solely in production rates and costs functionalized as distribution-related are included solely in distribution rates.[652]

Notwithstanding Mr. Lacey's diminishment of Mr. Zakem's concern, objecting that Mr. Zakem is not "focused on the benefits enjoyed as a result of incentive compensation," this PFD finds that Mr. Lacey's assertion that the relevant costs have been properly functionalized is uncontradicted on this record. In future cases, DTE should be prepared to provide a more-detailed response to concerns raised by intervenors.

5. <u>Customer Costs</u>

Mr. Lacey's testimony included a presentation of "customer-related costs by rate class" which he used to determine monthly customer charges of $29.61 for residential customers, $15.47 for commercial secondary customers, $1,359.14 for primary customers, $1,019.61 for subtransmission customers, and $655.77 for lighting customers. This section considers the analytical method proposed by DTE for determining monthly customer costs. The recommended monthly customer charges for each rate are discussed in section B below.

[652] See Lacey, 3 Tr 438-439 (emphasis added).

Mr. Lacey presented his analysis in Schedule F1.3 of Exhibit A-13 and testified:

> These customer-related costs are determined using a combination of direct assignment and allocated costs. Customer-related costs include 100% of meter costs, overhead and underground services, customer accounting costs, uncollectibles, and customer service expenses. The customer-related portion of poles & fixtures, overhead conductor, underground cable and conduit, and line transformers was determined using the minimum-size distribution system method. Finally, a share of distribution-related general plant, employee pensions & benefits, A&G expense and taxes collected under the Federal Insurance Contributions Act (FICA) are allocated to customer-related distribution costs.[653]

He testified that he used the "minimum-size distribution system method" referenced in the NARUC Manual, and figures from an internal DTE report entitled "A Look at the Allocation of Distribution Investment to Demand and Customer Components." He also testified that Duke Energy Progress, Inc. (Duke Energy) uses this method to classify a portion of its distribution accounts as customer related.[654] Mr. Lacey acknowledged that DTE proposed this same method in Case No. U-17767 and the Commission did not approve it.

Mr. Townsend objected to Mr. Lacey's analysis:

> As acknowledged by Mr. Lacey, the method used by the Company to determine customer-related costs was rejected by the Commission in the last rate case.
>
> <u>It is critical to recognize that the majority of the costs DTE classifies as customer-related are allocated to classes on the basis of *demand*, rather than allocated based on the number of customers.</u> It is not reasonable or rational to first *allocate* costs on the basis of *demand* and then classify the cost as customer related.[655]

Among the examples he gave are: poles and fixtures, overhead and underground cable, and line transformer--which he testified are allocated in the cost of service study

[653] See 3 Tr 425-426.
[654] See 3 Tr 427.
[655] See 3 Tr 61 (emphasis in original).

using non-coincident demand and customer maximum demand allocators; general plant, pensions and benefits, and administrative and general expense—which he testified are allocated in the cost of service study based on distribution plant in service, which is in turn allocated largely on a demand basis; and uncollectible expense, which he testified is allocated based on historical write-offs by class and does not vary directly with the number of customers.[656] He also testified that Mr. Lacey used the same DTE internal report that it used in Case No. U-17767, which Mr. Townsend presented as Exhibit KC-2. He testified that report does not have the hallmarks of an actual detailed study, but instead has the indicia of an illustrative presentation:

> In short, DTE has used what appear to be illustrative examples from a 37- year-old report to classify as "customer-related" a host of costs that had already been allocated to classes on the basis of demand. This approach is simply unreasonable at multiple levels. In my opinion, there is no credible evidence in DTE's filing that customer-related costs are remotely close to what the Company claims.[657]

He also noted:

> Ironically, the author of the report recommends *against* using either the minimum system or the zero-intercept allocation methods, and instead recommends allocating the applicable distribution plant accounts 100% on demand.[658]

Mr. Townsend also did not accept the Duke Energy study as having a bearing on the customer-related portions of DTE's system, and he noted differences between Duke Energy's cost of service allocations for customer-related costs and DTE's allocations.[659] Mr. Townsend presented a revised version of DTE's analysis which excluded nine types of costs from the calculation of the D11 primary-voltage customer-related cost, and

[656] See 3 Tr 61-62.
[657] See 3 Tr 64.
[658] See 3 Tr 64.
[659] See 3 Tr 64-66.

recommended a customer cost of $121 per month, as shown in Exhibit KC-3, rather than the $1,359.14 calculated by DTE. He testified that his approach could also be used for the other rate classes.[660]

Mr. Jester took issue with Mr. Lacey's testimony, and his reliance on a Duke Energy filing and the NARUC MANUAL:

> Mr. Lacey states that he relied on the Duke Energy classification as support for using the minimum-size distribution method to classify accounts as customer-related. As I explained below, the NARUC Manual states that the minimum-size distribution method is used to classify accounts as demand-related. Thus it has no bearing on the question of what costs should be allocated as the marginal cost of attaching a single customer, which this Commission has stated is the appropriate criterion to establish fixed customer charges. I should also note that Exhibit MEC-2 indicates that the Duke Energy classification was the only such benchmark that Mr. Lacey relied on. A single benchmark does not verify that a method is accepted or relied upon in a business or industry, in my opinion.[661]

He testified that the "minimum-size distribution method" does not accurately identify the marginal costs of customer attachment:

> The economically sound principle, recognized by this Commission, for establishing a fixed monthly charge per customer is to include only those costs caused by the customer having access to the system. To see that this does not include the distribution system costs allocated by the minimum-size distribution method one only needs to consider the effects of adding or decommissioning a customer along an existing distribution line. Adding a building and service on a vacant lot in a developed area already served by distribution does not add to the poles and fixtures, overhead conductor, underground cable and conduit, and line transformers in the distribution system. It only adds a service drop, meter, customer account, servicing thereof, and perhaps a distribution transformer. Similarly, if a building is abandoned and demolished and service is terminated, there is not a reduction in the minimum-size distribution assets that are required.[662]

---

[660] See 3 Tr 67.
[661] See 5 Tr 1596-1597.
[662] See 5 Tr 1597-1598.

While discussing certain potentially quite complex alternatives Mr. Jester recommended that the Commission reject DTE's use of the "minimum-size distribution system method" and follow its past practice of limiting customer monthly charges to those costs that are generally recognized as the marginal costs of connection, metering, billing and customer service.[663]

In his rebuttal testimony, Mr. Lacey addressed Staff's analysis, contending that Staff correctly accepted the costs identified in the NARUC manual as 100% customer-related, but did not include costs identified as being both demand and customer related.[664] Mr. Lacey characterized Mr. Townsend as "confused" on the difference between classification and allocation of costs, asserting that the section he cites of the NARUC Manual is in the cost allocation section, not the cost classification section.[665] He also testified that Mr. Jester commended allocating distribution costs on the basis of energy, in conflict with the NARUC Manual and the principle of cost causation.[666]

As the parties objecting to DTE's study argue, the Commission reviewed the same basis study in DTE's last rate case and refused to accept it:

> The Commission concurs with the other parties' claims that DTE Electric's COSS was flawed because it included a multitude of costs that, although customer-related, are not costs that vary with the number of customers on the system. As the Staff and others pointed out, the Commission has determined that the costs to be included in the customer charge are the marginal costs associated with attaching a customer to the system. In addition, as the Staff observed, the NARUC Manual likewise supports using only the marginal costs of customer attachment in developing a customer charge. Accordingly, the Commission finds that customer charges for residential and commercial secondary customers should

---

[663] See 5 Tr 1602.
[664] See 3 Tr 432-435.
[665] See 3 Tr 436.
[666] See 3 Tr 437.

> remain at their current levels, $6.00 per month for residential customers and $8.78 for commercial secondary customers.[667]

DTE has not provided any new analysis or additional reason to reconsider the Commission's decision, reached less than one year ago. This PFD finds that Mr. Lacey's study should not be relied on as determining the appropriate costs to recover through fixed monthly customer charges.

B. Rate Design and Tariffs

As discussed in section B, the principal disputes among the parties involve the monthly customer charges, voltage level discounts for the Primary Rate D11, interruptible and standby service rate design, the choice tariff, and the AMI opt-out tariff.

1. Monthly Customer Charge

As shown from the discussion above regarding Mr. Lacey's customer cost allocation method, the monthly customer charges to use in rate design are controversial. While DTE relies on Mr. Lacey's testimony to support increasing the monthly customer charges, several witnesses make alternate recommendations.

a. *Primary customers*

DTE did not recommend revisions to the monthly service charge for primary-voltage-level customers, which was set at $275 per month in Case No. U-17767. As discussed above, Mr. Townsend objected to DTE's cost study. He testified that DTE's cost study does not justify this charge for primary customers taking service at the primary voltage level, and based on his analysis as shown in Exhibit KC-3, the current monthly service charge should be reduced to $121.

[667] See December 11, 2015 order in Case NO. U-17767, pages 119-120.

In his rebuttal testimony, Mr. Bloch testified that he opposed reducing the charge noting that he had not recommended increasing it above the $275 level set in the last rate case. He further testified that if he were to recommend a change it would be to increase the charge in line with Mr. Lacey's study.[668] DTE relies on Mr. Lacey's testimony in its brief.

In its brief, MEC-SC-NRDC also support Kroger's recommended customer charge for Rate D11 Primary Voltage:

> Kroger, in its Initial Brief, presented testimony by Witness Neal Townsend that explained the company's incorrect calculation of its Rate D11 Primary Voltage customer service charge. Specifically, the customer service charge for D11 Primary Voltage will remain $275 per month, though DTE calculated the customer cost for this rate to be $1,359.14 per month. Kroger demonstrated that, with a proper allocation of customer- and demand-related accounts, the correct customer charge for this rate is $121 per month. Kroger's position on this issue is consistent with the position of MEC-NRDC-SC related to fixed customer charges for residential and commercial customers in our Initial Brief. We support and adopt Kroger's position with respect to the customer service charge for Rate D11 customers, as well.[669]

Recognizing that the Commission set this monthly charge at $275 in Case No. U-17767, after considering Kroger's recommendation for a lower charge and DTE's recommendation for a higher charge,[670] this PFD recommends that the Commission retain the $275 monthly charge in this case, and revisit the charge again in DTE's next rate case. At that point, as discussed below, the Commission should be able to consider the monthly charge and other rate design changes to promote energy efficiency and demand response, as discussed in more detail below.

[668] See 3 Tr 487-488.
[669] See MEC/SC/NRDC reply brief at page 8.
[670] See December 11, 2015 order, Case No. U-17767, pages 117-118.

b. Residential Customers

Relying on Mr. Lacey's study, discussed above, Mr. Williams proposed to increase monthly customer charges for the residential rate schedules from $6.00 to $9.00 per month as a gradual move toward the higher level indicated by the study.

Ms. Rivera testified that Staff recommends a monthly customer charge for residential customers of $7.50 based on Mr. Putnam's analysis. Consistent with this recommendation, she also recommended that the Senior Citizen charge be $3.75 and the RIA credit be $7.50.[671]

Mr. Jester objected to high fixed charges as unreasonable and unjust, analogizing to other businesses with high fixed costs that do not recover their costs through fixed charges.[672] He also testified that increasing fixed charges adversely affects customers with low incomes relative to high incomes explaining that low-income customers tend to have below-average consumption. He testified that DTE's residential low-income program only mitigates the impact of a higher fixed charge to a limited extent given the limited participation in the program. He also testified that increasing fixed charges reduces customers' ability to save by conserving electricity, thereby reducing the benefits of energy optimization programs, and reduces the economic benefits of distributed generation.[673]

This PFD finds Staff's recommendation reasonable given Mr. Putnam's analysis, Ms. Rivera's testimony, and the fact that the Commission did not increase the monthly customer charge in Case No. U-17767.

---

[671] See 5 Tr 1537.
[672] See 5 Tr 1602-1605.
[673] See 5 Tr 1606-1608.

c. Commercial Customers

Ms. Holmes relied on Mr. Lacey's study, discussed above, to propose increases in the monthly customer charges for the commercial rate schedules D3, D3.2, D3.3, and R8 from $8.48 to $16 per month, and for rate schedule D4 from $13.67 to $16 per month. Mr. Isakson recommended that the monthly customer charges be limited to $11.25 per month based on the results of Mr. Putnam's analysis. While MEC/SC/NRDC's arguments and Mr. Jester's testimony also argue in favor of keeping the commercial rate monthly charges low, Staff's analysis reasonably balances these concerns with a cost-based approach.

2. <u>Primary Rate D11 Voltage Level Discounts</u>

ABATE argues that DTE's rate design does not provide adequate voltage level discounts for subtransmission and transmission customers on Rate D11. Mr. Dauphinais testified that DTE's voltage level discount does not adequately reflect the lower cost to serve transmission and subtransmission customers because only the energy charge is discounted with no discount to the demand charge.[674] He testified that because subtransmission and transmission customers have lower loss factors than primary customers the demand charge should be lower, all else equal. He cited a DTE workpaper showing different loss factors by voltage-level customer: "That means that to serve a transmission level customer, DTE Electric will construct less production plant than it will to serve a primary level customer."[675] He presented Exhibit AB-21 to show what he considers the resulting subsidies by voltage level. And, he presented two alternative rate designs to eliminate these subsidies: in his first proposal, rates are set

[674] See 6 Tr 1966.
[675] See 6 Tr 1967.

for each voltage level with no additional discount, as shown in Exhibit AB-22; in his second proposal, the rate design parallels DTE's rate design, as shown in Exhibit AB-23. He testified that the same approaches can be used with whatever revenue target the Commission adopts in this case.[676]

In his rebuttal testimony on this issue, Mr. Bloch testified that Mr. Dauphinais's recommendations are essentially the same recommendations rejected by the Commission in Case No. U-17767.[677] He explained that in that case, the Commission adopted Staff's method for determining the voltage level power supply charges.

Mr. Isakson testified in rebuttal that subtransmission and transmission customers are not subsidizing primary customers under the current discount method. He explained that the voltage level discount for subtransmission customers is based on the average of the differences between subtransmission and primary customers' energy and demand loss factors, and likewise the voltage level discount for transmission customers is based on the average of the differences between transmission and primary customers' energy and demand loss factors:

> Procedurally, the subtransmission demand loss factor is subtracted from the primary demand loss factor and the subtransmission energy loss factor is subtracted from the primary energy loss factor. The average of those two differences is then multiplied by the average Rate D11 and D8 power supply energy charge (the two rates share the same energy charges) to arrive at the subtransmission voltage level discount. The same method is applied for transmission using the average transmission loss factor differences. This method was developed by Staff in the Company's previous rate case . . . and the Commission found that, "… the adjusted voltage level discounts, based on loss factors, shall be incorporated into rates as recommended by the Staff."[678]

[676] See 6 Tr 1969-1972.
[677] See 3 Tr 485.
[678] See 5 Tr 1295, citing December 15, 2015 order in Case No. U-17767.

He explained ABATE's proposal as follows, characterizing it as reallocating costs through rate design rather providing a discount:

> Essentially, they are recommending that the energy and demand loss factors be applied to customers' sales (i.e. kWh and kW sold) rather than to the rates at which those sales are charged. Both of ABATE's proposals use the same principal of altering sales, but differ from one another by separating energy and demand discounts in the first proposal, and in the second proposal, combining them like in the currently approved rate.[679]

He further testified that by relying on sales, ABATE erroneously creates the appearance of a subsidy:

> The underlying analysis performed by ABATE witness Dauphinais to show a subsidy among D11 customers is based on his alteration of sales, which is then applied to the overall power supply revenue requirement for the rate. In effect, the alteration of sales creates the appearance of a subsidy where, in actuality, there is none. Staff disagrees with ABATE's method of creating a cost of service allocator in the rate design step, and thus disagrees with using the method to justify the endeavor (i.e. correcting a nonexistent subsidy) to begin with. The current, Commission-approved method should also be approved in this case.[680]

This PFD finds that the current method recommended by Staff should be continue to be used. The Commission has recently addressed ABATE's concerns and concluded that there is no improper subsidy. Mr. Isakson's testimony explains the issue and is persuasive on this matter.

3. Interruptible Service—Rider 10

Mr. Dauphinais objected to DTE's proposed administrative charge for this rate schedule, which he testified is 28% of the total full service power supply cost. He testified that DTE assigned Rider 10 costs remaining after deducted expected revenues from the MISO Energy Charge, the Net Transmission MISO Market Charge, and the

[679] See 5 Tr 1296.
[680] See 5 Tr 1296-1297.

voltage service adder.[681] He testified that the MISO energy charge is understated, citing an approximately $6 million difference between the amount included in DTE's Exhibit A-14, Schedule F-3, page 31, and the amount assigned in the cost of service study, Exhibit A-13, Schedule F1.1, page 3. He testified that even the amount in the cost of service study is too low and the correct figure to use in rate design in an additional $2 million greater. He also recommended a small increase (approximately $44,000) in the MISO transmission market expense used in the rate design.[682] He presented Exhibit AB-24 to show revising these components leads to an administrative charge of $16.2 million.

Mr. Dauphinais also objected that the Rider 10 administrative charge includes production O&M costs. He testified that $11.4 million should be excluded arguing that because Rider 10 is not allocated any production fixed costs, it should not be allocated any production O&M costs.[683] He testified that excluding these costs would reduce the revenue to be collected from the administrative charge to $4.9 million.

Mr. Lacey and Mr. Bloch both provided rebuttal testimony in response. Mr. Lacey testified that his initial cost of service study contained an error, which he corrected, reducing the R10 production revenue requirement by $6.3 million, and the revenue to be collected by the administrative charge to $17.4 million.[684] Mr. Bloch objected to Mr. Dauphinais's recommendation to remove all production O&M from this rate:

> R10 customers receive benefit from DTE generation resources in the form of less volatile and lower MISO energy prices paid by R10 customers. This

[681] See 6 Tr 1972.
[682] See 6 Tr 1973.
[683] See 6 Tr 1975-1977.
[684] See 3 Tr 439-441, Exhibit A-36, Schedule Z1.

> issue was also previously addressed in Case No. U-16472. On page 100 of the Commission's October 20, 2011 Order, "The ALJ found that the maintenance of production equipment has a benefit to R10 customers for standby generation and grid reliability purposes." ….. "The Commission is not persuaded that R10 customers are overallocated production costs simply because more of their load is purchased through MISO. The Commission agrees with the ALJ and adopts the findings and recommendations of the PFD." In addition, the Commission reaffirmed its position by again rejecting the very same request by ABATE in DTE Electric's last general rate case.[685]
>
> Mr. Isakson also provided rebuttal testimony on this topic, explaining:
>
> The administrative charge contains all of the revenue requirement allocated to R10 in Staff's cost of service study *not* associated with the MISO energy market costs and network transmission costs. The Commission has previously found that the costs allocated to R10 customers do not represent an over allocation. . . . The evidence presented by ABATE in the instant case is merely repetitious of the arguments they made in previous case, and those arguments remain unpersuasive. Therefore, the rate design and cost allocation methods used by Staff should be approved.[686]

This PFD finds that the Commission has approved Staff's rate design and ABATE has not presented a compelling basis to ignore the Commission's prior decision.

4. Standby Service Rider 3 (Tariff)

Mr. Bloch testified that the Rider 3 rate provides standby service for various customers with generation facilities operating I parallel with DTE's system.[687] After discussing MCL 460.10a regarding self-service power, Mr. Dauphinais explained that self-service power predates the existence of retail access in Michigan and is separate from choice service. He explained the importance of standby service to self-service power customers and testified that as a result, utilities are generally require to provide bundled retail standby power to self-service customers based on their cost.

[685] See 3 Tr 485, citing December 11, 2015 order in Case No. U-17767, page 123.
[686] See 5 Tr 1297, citing November 20, 2011 order in MPSC Case No. U-16472, page 100.
[687] See 3 Tr 469.

Mr. Dauphinais described the “backup service,” “maintenance,” and “supplemental power” components of standby service.[688] Citing the Public Utility Regulatory Policy Act requirements he testified that FERC rules require that the rates for backup and maintenance service provided to Qualifying Facilities reflect the cost of service.[689] He testified that the underlying policy reasons supporting federal policy for QFs support the provision of backup and maintenance power to facilities that are not QFs including “combined heat and power” facilities or CHPs.[690]

Mr. Dauphinais testified that DTE has two options for obtaining the power to provide backup and maintenance service to standby customers, the “generation fleet” and the “wholesale market” approaches. He described these approaches[691] and testified that the “wholesale market” approach is more appropriate:

> When DTE Electric meets these load obligations through market purchases from MISO rather than with its own generation, its need for capacity in its long-term resource plans is reduced. More importantly, DTE Electric’s long-term resource plan is designed to serve an aggregate average load factor that is in excess of 50%. However, the load that is served under Rider R3 has a much lower load factor (typically 10% or less) because of the reliable nature of CHP facilities. If the Generation Fleet approach option is utilized, then standby service customers will be inappropriately allocated costs associated with DTE Electric’s base load and intermediate facilities, when, in reality, it is only DTE Electric’s peaking facilities that are required to meet standby service load obligations due to the very low load factor of standby service.[692]

He also testified that both options should be available to customers and further testified that DTE used to offer both options, but eliminated the wholesale market option

[688] See 6 Tr 1981.
[689] See 6 Tr 1981-1982.
[690] See 6 Tr 1982-1985.
[691] See 6 Tr 1985-1987.
[692] See 6 Tr 1986-1987.

in its last rate case. He testified that the cost of service using the wholesale market option was not analyzed in Case No. U-17767.

Mr. Dauphinais also took issue with DTE's current and proposed rates for this service, characterizing them as excessive. He testified that the reservation fee is excessive and punishes the customers with the best-performing on-site generation. In his view, the reservation charge should be on the forced outage rate of the best-performing customer so as not to require that customer to pay more than their own cost of service. He testified that the current reservation fee represents 12.1% of the Rate D11 demand rate, equivalent to all customers experiencing an average of 3.7 outage days per month.[693]

Mr. Dauphinais also testified that the current and proposed daily on-peak demand charges are excessive. Objecting that the charges are almost one-third of the Rate D11 demand charge, he testified that it is more appropriate to set the on-peak daily backup demand rate based on the number of peak days in a month:

> This rate structure would ensure that standby customers are paying on-peak demand charges based on their expected contribution to DTE Electric's monthly system peak demand rather than a punitive rate design that linearly ramps up such that four on-peak forced outages in a single month incurs a full Rate D11 charge. DTE Electric's current and proposed rate design results in it receiving revenues far in excess of DTE Electric's cost of service to provide the standby service.[694]

Mr. Dauphinais proposed a model for standby service rate design that includes a wholesale market option with the reservation charge, backup demand charge, and daily maintenance charge based on the difference between the MISO Planning Resource Auction clearing price and the Zonal Delivery Benefit credit for Zone 7. Energy charges

---

[693] See 6 Tr 1989-1990.
[694] See 6 Tr 1991.

would be based on the MISO real-time locational marginal price with no PSCR charges. He also acknowledged that there should be a direct pass-through of MISO transmission charges.[695] Mr. Dauphinais discussed the benefits of this approach and considered potential criticisms including recommending a limit on the ability of customers to switch between options.

For his generation fleet option, Mr. Dauphinais recommended that the reservation charge be reduced to 3.6% of the Rate D11 demand rate and that the daily demand charges and daily demand backup charges be reduced to 5% of the Rate D11 charge with the daily maintenance charge correspondingly reduced to half the backup charge.

In his rebuttal testimony, Mr. Bloch first took issue with Mr. Dauphinais's premise that the elimination of the market pricing option from Rider 3 without appropriate analysis. He testified that he had recommended elimination of the market option in Case No. U-17767 because it had been created in the first place as the result of a settlement agreement and did not have cost support.[696] He testified that ABATE's proposal in that case was to have a MISO-based option that would have resulted in intra-class subsidies and was property rejected by the Commission in its order:

> I disagree with Witness Dauphinais's position that he is not advocating for any subsidies for Rider 3 customers. The concept of allowing customers to be priced from the wholesale market when DTE's production costs are assigned on an embedded cost basis will create subsidies since power supply costs in the wholesale market are not the same as DTE's power supply embedded costs. For this reason, his position will certainly result in subsidies.[697]

---

[695] See 6 Tr 1991-1994.
[696] See 3 Tr 477.
[697] See 3 Tr 478.

Mr. Bloch took issue with several of Mr. Dauphinais's assertions including his recommended rate design for each of the options he proposes.[698]

Mr. Revere addressed ABATE's recommendations in his rebuttal testimony. He testified that Staff agrees with the concept of treating R3 as a separate class but believes it is premature to take a position on how rates should be designed for R3 as a separate class in the absence of a cost of service study. He testified that Staff does not believe it is appropriate to include the wholesale market option:

> While the proposed inclusion of a demand charge based on the Cost Of New Entry (CONE) significantly improves on the now eliminated option that lacked a demand charge entirely, the proposal still fails to capture the actual value of the service provided to standby customers. As Staff noted in its PURPA Technical Advisory Committee Report on the Continued Appropriateness of the Commission's Implementation of PURPA:
>
> "…to obtain cheaper energy from an NGCC (as opposed to a CT), the additional capacity costs to build an NGCC are incurred over and above the cost to build a CT." (p. 23).
>
> Staff recommended adding this difference to the Locational Marginal Price (LMP) to reflect a "true energy value", as a failure to do so leads to a result (CONE + LMP) that does not take into account that the LMP is lower than it would be outside of the cheaper energy the more expensive capacity provides. (Ibid.) The same logic applies here. If the proposal were adopted, it would lead to the very subsidies the original market option was eliminated to avoid. Therefore, the proposal should be rejected.[699]

This PFD finds that the Commission rejected ABATE's arguments in Case No. U-17767 and there is no new information on this record to recommend revising that determination. Instead, this PFD recommends that the Commission adopt Mr. Revere's recommendations, decline to require the "wholesale market option," decline to revise the rate design, and require that Rider 3 be treated as a separate rate class in DTE's next rate case cost of service study.

---

[698] See 3 Tr 480-484.
[699] See 5 Tr 1370.

5. Community Lighting Tariff and Rate design

Mr. Johnston presented DTE's recommendations for community lighting. He presented a cost-based rate proposal as well as a proposal based on an equal percentage increase in light of the collaborative ordered in Case No. U-17767. He also discussed changes DTE is proposing to its community lighting program. Among these changes, he testified DTE is now proposing to replace failed (obsolete) mercury vapor lamps with LEDs, rather than high-pressure sodium. In addition, he testified DTE is proposing to revise the financing in lieu of a contribution in aid of construction (CAIC), establish a special order materials charge, establish an underground service option, replace experimental emerging lighting technologies tariff with a standard LED rate schedule, and move to volumetric surcharge for the unmetered class. He also testified that DTE is proposing to remove two rate options, the de-energized and dusk to midnight rate options, on the basis that they are rarely used.

Mr. Johnston testified that DTE is proposing to change the structure of charges to basically unbundle the per lamp charge into a separate luminaire charge and an energy component. Under this proposal the energy charge will be based on the calculated consumption values of the various lighting technologies and sizes, and the luminaire charge will be a fixed charge per unit depending on whether it is served overhead or underground.[700]

Mr. Johnston described his cost-of-service-based rate design. He described how he determined the luminaire charges included in Schedule E1 of Exhibit A-14. He also described how the Rate Schedule D9 charges for residential and commercial lighting

[700] See 4 Tr 1165.

were determined. And he described his equal-percentage-increase alternative that would defer a determination on the final rate methodology to the collaborative:

> DTE Electric believes that the Outdoor Lighting Tariff rates should be cost-based as described and presented in my testimony and exhibits. However, DTE Electric is proposing that the Rate Schedule E1 and D9 rates, including the existing LED technology served under the EEL Technology Provision provided in the tariffs, for purposes of this filing, be increased on an equal percentage basis as the Company works with the MPSC Staff and other interested parties through the MPSC-Ordered Lighting Collaborative.[701]

Mr. Johnston presented revised lighting tariffs in Schedule G1 of Exhibit A-15.

Ms. Rivera testified that Staff is generally supportive of the company's community lighting changes. Addressing the financing charge associated with lighting conversions, she recommended that the tariff specify the final weighted average cost of capital approved in this case. Second, she recommended that the language be clarified to show that it is available for conversions as well as new business. And third, she encouraged DTE to explore the potential of recovering third-party financing through utility billing, citing the Commission's June 9, 2016 order in Case No. U-18100, approving this option for lighting technologies other than mercury.[702] She also testified that Staff agrees with DTE's proposal to replace failed mercury lamps with LED lights rather than high-pressure sodium.[703]

Ms. Rivera further testified that Staff does not support eliminating the de-energized and dawn-to-dusk tariff options and she recommended that the structure of the tariff be changed to show a breakdown of per luminaire costs, power supply costs, and the total per-light monthly charge.

---

[701] See 4 Tr 1174.
[702] See 5 Tr 1538-1540.
[703] See 5 Tr 1540.

Mr. Revere addressed rate design for the lighting tariffs. He discussed the lighting collaborative and testified that Staff now believes the lighting rates should begin moving toward cost-of-service-based rates especially for LED lighting.[704] He explained Staff's rate design based on Staff's revenue requirement with the impact to any customer capped at three times the overall increase.

In his rebuttal testimony, Mr. Johnston testified that as a result of the lighting collaborative DTE no longer wants to eliminate the de-energized or dawn-to-dusk options. He noted a technical correction that would need to be made to Staff's rate provisions to reflect the appropriate lamp counts, as shown in his Exhibit A-35, Schedule Y1. He testified that this schedule presents revised proposed rates, calculated in accordance with Mr. Revere's methodology, with the caps that he described.[705]

The briefs of the parties also reflect general agreement on the appropriate lighting tariffs and rate design.[706] In its initial brief, Staff reviews Ms. Rivera's recommendations indicating that DTE has agreed to continue the de-energized and dawn-to-dusk options and supporting DTE's proposal to change the default mercury lamp replacement. Staff also recommends that the Commission adopt Staff's rate design as modified by DTE. On this basis, this PFD recommends that the Commission approve the revisions to the lighting tariffs agreed to by Staff and DTE including the de-energized and dusk-to-dawn offerings, approve the default replacement of mercury lamps with LEDs effective with the final order in this case, and adopt the rate design presented by Mr. Revere as corrected by Mr. Johnston. In addition, this PFD

[704] See 5 Tr 1365.
[705] See 4 Tr 1184-1188.
[706] See Staff brief, pages 98-99, DTE brief, pages 135-130.

recommends that the Commission endorse Staff's recommendations to DTE to explore a third-party financing option, break out lighting charges into components as explained by Ms. Rivera, and reach out to fiscally challenged customers to discuss LED conversions and prioritize LED conversions for those customers most affected by lighting rate increases as feasible.

6. Time of Use Rates

In Case No. U-17689 the Commission required DTE to revise its tariffs by January 1, 2016 to ensure that time-of-use rates and dynamic peak pricing are available to all customers who have had an AMI meter for at least one year and who choose to opt in.[707]

MEC/SC/NRDC acknowledge that as a result of this order, DTE removed the experimental status from its Dynamic Peak Pricing Rate (D1.8) and removed customer limits within that rate. In this case, Mr. Jester recommended that the Commission direct DTE to make Rate Schedule D1.8 the default schedule for all new residential and secondary commercial customers.[708] MEC/SC/NRDC also address commercial and industrial customers connected at primary, subtransmission, or transmission voltage. They argue that the Commission clearly included these customers within the ambit of its order and DTE has not provided time-of-use or dynamic peak pricing. Mr. Jester recommended that the Commission require DTE to expand its offerings for these customer classes.

In his rebuttal testimony, Mr. Bloch explained that rates for commercial and industrial customers already provide significant time-of-use price signals through

[707] See June 15, 2015 order, Case No. U-17689, page 35.
[708] See 5 Tr 1612-1615.

on-peak billing demands and on-peak and off-peak energy pricing.[709] He also indicated that the differential between the on-peak and off-peak prices could be increased. MEC/SC/NRDC argue in response that the Commission should adopt Mr. Bloch's alternative.[710]

In its brief, Staff argues that it supports the availability of time varying rates, and recommends that DTE encourage customers to join these rate structures. Staff, however, disagrees that Rate D1.8 should be the default rate. Staff acknowledges many advantages of these rates, but expresses a concern that Rate D1.8 has several daily price changes and a critical event rate that requires notification from the company: "With effective advertising, education, and encouragement from the Company, customers will be more successful in responding to time-based rates than if all new, possibly unready customers are automatically enrolled in this complex rate."[711] Staff also supports modifying the on-peak and off-peak pricing differential.

MEC/SC/NRDC argue in reply that DTE does not have any specific TOU campaigns planned. It also argues that education about the TOU rates would be more effective at the time new customers enroll than using mass mailings and bill inserts.[712]

This PFD recommends that the Commission adopt Staff's analysis regarding whether Rate D1.8 should be the default rate for new customers. Time of use rates have not been available to all residential customers for a full year. Many have not yet had an AMI meter for a full year. DTE is still exploring ways to interest customers in the capabilities of the new meters. Careful consideration of the success of the voluntary

---

[709] See 3 Tr 489.
[710] See MEC/SC/NRDC brief, pages 74-76.
[711] See Staff brief, page 90, Revere, 5 Tr 1303.
[712] See MEC brief, page 7.

rates in future cases may call for a different response. But, in any event, it is clear that prior to automatically enrolling customers in Rate D1.8 or a similar rate the Commission and Staff should have an opportunity to review the educational plan and promotional materials.[713] The Commission has very recently called for further analysis of DTE's demand response offerings in Case No. U-17936, which should provide all parties a forum for review and comment on DTE's implementation of this tariff.

Regarding commercial and industrial rates, in that same case, the Commission has required DTE and Consumers Energy to provide a detailed report on the status of their respective large commercial and industrial demand response offerings in each of their next rate case applications:

> The reports shall contain, at a minimum, a summary of all discussions that have been held with these customers, feedback received on current offerings, suggestions for program changes, and changes that have in fact been made as a result of these discussions.[714]

Given this process for addressing these issues, and in the absence of explicit comment from ABATE or other parties regarding the on-peak and off-peak pricing differential for Rate D11, this PFD recommends that the Commission defer consideration of that change as well.

7. <u>Retail Access Service Rider Tariff</u>

Mr. Bloch testified in support of adding the following paragraph (D) to the Retail Access Service Rider EC2, section E2.8, Exhibit A-15, Schedule G1, page 66:

> Customers not eligible to expand the retail access service load at their facility in accordance with the procedures adopted by the MPSC in Case No. U-15801 on September 29, 2009, must install separate metering, at their expense, in order to measure and bill the Full Service portion of their facility load. At the Company's sole discretion, the separate metering

[713] Staff initial brief, pages 89-90.
[714] See November 7, 2016 order in Case No. U-17936, pages 18-19.

> requirement may be waived if the installation of separate metering is impractical. Under this waiver, both retail access and full service loads will be estimated based on the metered load of the facility.

He explained the rationale for this language as arising from the Commission's September 29, 2009 order in Case No. U-15801 et al, for customers not in Groups One, Two, or Three, and therefore not eligible to receive choice service for the installation of new equipment or processes behind an existing meter if the level of choice participation is greater than the 10% cap. He testified that the language provides more clarity regarding bifurcation of expanded load, and reflects DTE's current practice.

Mr. Dauphinais testified regarding the changes DTE proposes to this rider:

> First, there needs to be better clarification as to the type of customer load that will be actually impacted by this provision. It is unclear from the direct testimony of DTE Electric witness Mr. Bloch what is meant by "new equipment." For example, does this proposed provision apply to the installation of any equipment to an existing process, and if it does, what is the criteria for applying the proposed provision? These questions are left unanswered by Mr. Bloch's testimony. Secondly, any decision that is made about the metering is proposed to be at the Company's sole discretion. Any customer who does not agree with the Company's decision should have some means of disputing the provision before the Commission, and a decision should be rendered in a timely fashion. Filing a complaint with the Commission could result in a customer not being able to expand the service until the regulatory process is completed.[715]

Mr. Zakem also testified regarding the changes DTE proposes to this rider. He agreed that the change matches the implementation rules in the Commission's September 29, 2009 order in Case No. U-15801 et al. Mr. Zakem recommended that the language be changed to read:

> Customers <u>who desire to expand load at their facility, where expand means to connect new load through an existing meter, but are</u> not eligible to expand the retail access service load at their facility <u>above the Cap on Choice Participation</u> in accordance with the procedures adopted by the MPSC in Case No. U-15801 on September 29, 2009, must install separate

[715] See 6 Tr 2002-2003.

> metering, at their expense, in order to measure and bill the Full Service portion of their facility load. ~~At the Company's sole discretion,~~ ~~t~~ The separate metering requirement ~~may~~ will be waived if the installation of separate metering is impractical. Under this waiver, both retail access and full service loads will be estimated based on the metered load of the facility.[716]

In his rebuttal testimony, Mr. Bloch insisted that DTE must have sole discretion to make the determination whether separate metering is impractical:

> The Company is solely responsible for the design and installation of its revenue meters. To meet that responsibility, the Company must have sole discretion to determine if the installation of separate metering is impractical and may be waived. The Company's proposed language addition to EC2 is only intended add clarity to the existing metering requirements and implementation rules, which the Company is already administering without incident.[717]

Mr. Bloch also responded Mr. Dauphinais's concerns, again emphasizing that tariff language is only proposed for clarification, and that the company is not aware of any complaints regarding the administration of the rules and does see the need for an expedited procedure.[718]

In its brief, ABATE urges the Commission to better define the load impacted and to provide a mechanism for resolving metering issues between DTE and the customers objecting that DTE's language provides it with "total control regarding the amount of load taking customer choice" and leaving choice customers without protection.[719] Energy Michigan argues that Mr. Zakem's modifications are reasonable:

> Taken as a whole, Mr. Zakem's modifications preserve the intent of the DTE tariff revisions and keep the final decision of "impractical" metering in the hands of the Company. At the same time Mr. Zakem's proposed modifications acknowledge that the utility does not have "sole discretion" to withhold a waiver unfairly even if the metering situation is impractical for

[716] See 6 Tr 1723-1724.
[717] See 3 Tr 487.
[718] See 3 Tr 486.
[719] See ABATE brief, pages 4, 38-39.

> the customer; they also allow the customer to have some voice in the process. Under Mr. Zakem's proposed modifications, if the customer does not agree with the Company on whether the metering situation is practical or not, the customer will have a right to register a complaint with the Commission, without the Company claiming that it has "sole discretion" under the tariff.[720]

This PFD finds that this record does not establish a basis for providing for expedited hearings as requested by ABATE. Without knowing the nature or type of disputes that may arise it is difficult to anticipate the types of procedures that would be appropriate, nor is a rate case the place that most parties would look to for guidance on such issues. DTE's request for clarifying tariff language is not unreasonable but it is not necessary to adopt language that provides for the utility's "sole discretion". As both ABATE and Energy Michigan argue, customers should be able to file a complaint with the Commission if they believe DTE is being arbitrary or discriminatory in the exercise of its discretion. On this basis, Energy Michigan's proposed language appears reasonable.

8. Residential Power Supply Charges

Mr. Coppola called for the Commission to require DTE to provide an evaluation of the current 17 KWh/day level used as the threshold for increased power supply charges for residential customers, testifying that the threshold had not been evaluated in over 30 years and differs significantly from Consumers Energy's threshold. The Attorney General urges the Commission to adopt this recommendation.[721] DTE did not provide rebuttal testimony on this topic, and did not oppose the request. On this basis, this PFD recommends that DTE provide the requested evaluation.

[720] See Energy Michigan brief, pages 9-10.
[721] See Attorney General brief, page 68.

9. AMI Opt-out Tariff

Mr. Sitkauskas testified that because DTE will not complete its AMI meter installation until 2017 it does not see any reason to modify the AMI opt-out tariff rates at this point in time. He testified:

> Yes. In its Order on page 98, the Commission required the Company to review its "opt out charges in either its next rate case or six months after completion of AMI meter installation, whichever occurs first." Since this is the next rate case filing and the Company has not completed installation of all AMI meters, we have conducted a review of the current charges as shown on Exhibit A-18, Schedule J3.[722]

He did present a "review" of the current changes in his Schedule J3 of Exhibit A-18. He testified that DTE had 6,700 opt-out customers as of the end of 2015 which is lower than expected. He testified that his Schedule J3 follows the format used in Case No. U-17053, including the same cost components, with supporting detail in the subsequent pages of the schedule.[723] He testified that if the updated costs are included in rates the initial fee would be $69.70 and the total monthly fee would be $10.63. He testified that DTE is not proposing to change the charges at this point in time, however, explaining that DTE believes the making charges at this time is premature and should be addressed post-implementation.[724]

Mr. Crandall testified on this topic:

> In this docket DTE is attempting to further exacerbate this situation by seeking authorization to sharply increase the opt-out fees. DTE witness Sitkauskas is proposing (see Exhibit A-18) not to reduce or hold the controversial assessments steady but rather to increase the initial incremental special assessment by approximately 7% to -$69.70 and to sharply escalate the monthly incremental special assessment to $10.63. If approved this represents a new combined monthly cost to customers (imposed against the customers will) of $16.44/month for the first year

[722] See 4 Tr 1040-1041.
[723] See 4 Tr 1042.
[724] See 4 Tr 1043.

> following installation of a smart meter in order to avoid being coerced into taking the unwanted AMI metering service from DTE. This request is being made by DTE without regard to the concerns and vehement opposition of thousands of its long-standing, good-paying customers who oppose sophisticated and intrusive metering technology being installed and operated on their property.[725]

Further, he testified that DTE has not provided an adequate basis in its filing to demonstrate the "financial viability and reasonableness" of opt-out charges that are now in effect.[726] He testified that AMI savings should be returned to customers and costs should not be assigned to opt-out customers who are "not the causer of the costs."[727] He testified that all customers including opt-out customers are paying costs in rate base for the AMI program, and opt-out customers are also burdened with additional charges that he chacterized as "punitive pricing" and a "penalty."[728] He recommended that the Commission review updated cost elements presented in this case concluding that he could not find "substantial, thorough and sufficiently detailed cost information" to justify significant increases in the current charges.[729] Mr. Crandall also recommended revising the opt-out tariff to require "pre-installation notice and customer consent", and to eliminate the opt-out charges.[730] He presented as Exhibit RCG-2 a revised tariff that he recommends the Commission adopt.

Mr. Isakson addressed this topic in his rebuttal testimony explaining that DTE is not seeking to increase the opt-out charges in this case. He also testified that Staff supports that recommendation. He reviewed the history of how the charges had been set in Case No. U-17053 to address Mr. Crandall's testimony that the initial charges

[725] See 6 Tr 1754.
[726] See 6 Tr 1754.
[727] See 6 Tr 1755.
[728] See 6 Tr 1757.
[729] See 6 Tr 1758.
[730] See 6 Tr 1760-1763.

were arbitrary explaining that although the charges were based on estimates, the estimates were reviewed for reasonableness.[731] He also discussed the cost detail included in Schedule J3, which Mr. Crandall did not specifically address. Mr. Isakson also explained that customers paying the opt-out charges are not paying for the AMI program costs as provided in the Commission's order in Case No. U-17053 and affirmed in the Commission's order in Case No. U-17767. Likewise, he explained that the charges are not punitive but cost-based.[732]

In its briefs, the RCG argues that the opt-out charges should be eliminated or sharply reduced. In citing Mr. Crandall's testimony DTE does not address Mr. Isakson's rebuttal testimony. The RCG also renews arguments that it made in Case No. U-17767 recommending changes to the opt-out tariff. The RCG argues that the Commission should revise the opt-out tariff to require customer consent before an AMI meter may be installed by DTE and asks the Commission to conclude that it lacks jurisdiction "to infringe upon a customer's privacy and right to safeguard his or her health and safety, or to impose opt out charges for their refusal to waive their constitutional rights." These arguments have been fully addressed by the Commission in past cases and the RCG brings no new information or analysis that would justify reconsideration of those decisions.

The RCG also argues that in setting monthly surcharges the Commission should consider that the billing rules permit customers to self-read and report their energy consumption each month, subject to an annual reading by DTE. DTE responds that the same billing rules permit DTE to read the meter any time. While there is no information

---

[731] See 5 Tr 1298.
[732] See 5 Tr 1300-1301.

on this record that would shed light on the actual extent of self-reporting, that is an issue that can be considered when the Commission next evaluates the opt-out charges. In that context, while the rule clearly specifies DTE's rights to read meters on a regular basis, the company also should be reasonable and prudent in exercising these rights.

Based on the testimony and exhibits in the record, the PFD recommends that the Commission accept DTE's and Staff's view that it is premature to revise the opt-out charges, and instead that the Commission require DTE to file a separate application for review of those charges within 6 months of completing the AMI meter installations.

X.

OTHER ISSUES

A. Revenue Decoupling Mechanism

Mr. Stanczak testified that DTE is proposing a revenue decoupling mechanism (RDM) in this case even though he acknowledges it is not yet lawful for the Commission to approve one. He testified that a well-designed RDM removes the utility's disincentive to encourage Energy Optimization (EO) under 2008 PA 295 by eliminating the negative financial impact on its earnings resulting from the reduction in energy sales. He testified that DTE's proposed mechanism would allow DTE to recover any sales reductions attributable to the company's approved EO program, to be determined in the annual EO reconciliations. He presented Exhibit A-23 to illustrate the mechanism. [733]

Mr. Dauphinais recommended that the Commission not approve the RDM contending that it shifts a portion of the risk of doing business away from DTE shareholders to the ratepayers. It will provide DTE the opportunity to earn significantly above its authorized rate of return and constitutes "piecemeal" ratemaking by looking

[733] See 4 Tr 1088-1089.

only at one component of the cost to serve. He noted that the Commission has reduced its reliance on tracking mechanism in recognition that 2008 PA 286 provides favorable rate treatment for utilities.[734]

Mr. Sullivan testified on behalf of NRDC. He explained the underlying policy regarding an RDM to remove a utility's disincentive to support all forms of energy efficiency. He testified that DTE's proposed RDM is not actually a decoupling mechanism, but an inferior "lost revenue adjustment mechanism."[735] He agreed with Mr. Stanczak's characterization of a revenue decoupling mechanism as removing "the link between utility sales and revenues," but testified that DTE's proposed RDM does not do this: "If DTE sells more electricity than the amount used to set rates, the utility will collect a windfall profit. Also, DTE's proposed RDM does not allow for the possibility of refunds to customers if DTE collects over its regulator-authorized revenue requirement."[736] Mr. Sullivan identified what he labeled "known drawbacks" of lost revenue adjustment mechanisms:

> • They do not remove the throughput incentive;
>
> • They are asymmetrical;
>
> • They can get costly, because in year one of the mechanism the utility collects lost revenues from the measures installed in the first year, and in year two of the mechanism, the utility collects lost revenues from the measures installed in the *first and second* years, and so on in the third year;
>
> • They can add contention to the process of estimating savings from programs, since these results are now used to determine the amount collected in the adjustment mechanism. See 5 Tr 1677.

[734] See 6 Tr 2004-2008.
[735] See 5 Tr 1273.
[736] See 5 Tr 1676.

He recommended that the Commission not approve DTE's mechanism if it legally authorized to do so, and recommended an alternative that he referred to as a "symmetrical revenue decoupling mechanism," with the further recommendation that the Commission limit the size of the adjustment.[737]

Mr. Zakem elaborated on his concern that it is premature to discuss a revenue decoupling mechanism in the absence of authorizing legislation:

> [T]he rules or guidelines of any such new legislation are unknown – how would the Commission know now that DTE's proposal would be in accord with any new legislation? Would DTE amend its proposal in this case? How can other parties critique a speculative proposal, or offer changes? To have or have not an RDM is a policy decision for the Legislature and the Commission, and a speculative, currently unauthorized proposal is a drain on the Commission's resources in people, time, analysis, and decision-making capacity.[738]

He also discussed other concerns, including concerns that DTE did not integrate its proposal with its current Energy Optimization performance incentive mechanism, did not adjust its rate of return to reflect a reduction in risk, and is proposing a mechanism inconsistent with the economic development plans.[739] He also expressed a concern regarding the potential allocation of costs.[740]

Mr. Townsend took issue with DTE's proposal, explaining:

> In practice, the implementation of energy efficiency programs does not necessarily imply that a utility will not be able to fully recover its costs. To the extent that a utility experiences overall net growth in retail sales, the impact of energy efficiency measures will be more than offset. As a result, a utility will not be likely to experience an absolute reduction in fixed-cost recovery that is reflected in rates at any point in time, even in the presence of mandated energy efficiency programs. For instance, the Company's annual sales forecas3 remains relatively flat from the projected period

[737] See 5Tr 1678-1679.
[738] See 6 Tr 1700.
[739] See 6 Tr 1700-1708.
[740] See 6 Tr 1704-1705.

(ending July 31, 2017) through year 2020 with continued increases in sales projected for the Commercial class.

> In general, when load grows above the level of billing determinants used in setting rates, the fixed-cost recovery that occurs as a function of volumetric sales, increases. In traditional ratemaking, utilities are not required to return this incremental fixed-cost recovery to customers. This incremental fixed cost recovery can be thought of as additional revenues that the utility is allowed to retain, rather than return to ratepayers. In light of DTE's relatively flat load forecast for the next few years, it is unreasonable to require customers to pay for any "lost margins" at this time.[741]

Mr. Coppola recommended against approving the RDM:

> The Company has not presented any evidence that the RDM is needed or that it is in the best interest of its customers. The Company is not in financial distress from under collecting revenues approved in rates. Quite to the contrary, in Exhibit A-17, I4 filed in this rate case and an update provided in response to discovery, the Company has shown that on a regulatory basis it has earned returns on equity of between 10% and 11.4% in the past six years, which are near or above its authorized rate of return. I recommend that the Commission reject the proposed RDM. The historical record shows that the Company does not need this mechanism to earn its authorized return. Furthermore, as the Commission recently stated in Case No. U-17735, it does not have the authority to order an RDM for electric utilities.[742]

Mr. Isakson testified that Staff opposes the company's proposed mechanism noting that it is currently unlawful for the Commission to do so. He also testified that if it becomes lawful for the Commission to adopt and RDM Staff would recommend an alternative mechanism meeting eight key conditions:

> 1) for the delivery calculation, revenues reflected in the calculations are equal to the total class revenue less customer charge, fuel and purchased power revenue, and other surcharge revenue;
>
> 2) for the power supply calculation, revenues reflected in the calculation are equal to total class revenue less customer charge revenue and other surcharge revenue;

[741] See 3 Tr 58.
[742] See 6 Tr 1785.

3) all months associated with the projected test year are excluded from true-up; thus,

4) the first annual reconciliation period commences with the first month following the end of the general rate case projected test year;

5) operation of the RDM terminates upon utility implementation of new rates (self-implemented or ordered) and must be re-approved in the next general rate case;

6) allocation of the qualifying revenue shortfall is by customer class, consistent with the calculation;

7) the actual revenue used in the calculation is weather-normalized in a manner consistent with the weather-normalization method approved by the Commission in the instant case; and

8) the continuance of the RDM is dependent on the legislatively-mandated energy optimization (EO) programs remaining in place.[743]

Mr. Revere provided additional details and explanations regarding Staff's view of an appropriate RDM.[744]

Based on the recommendations of the many witnesses testifying on this issue, this PFD concludes that it is premature for the Commission to adopt a revenue decoupling mechanism in advance of the legal authority to do so. Many factors would need to be addressed, as explained by several of the witnesses, to ensure that the revenue decoupling mechanism provides the appropriate incentives with appropriate ratepayer safeguards. There is also no demonstrated need for an RDM on this record, as Mr. Leuker testified that DTE's sales forecasting is not based on historical sales levels but on the efficiency of appliances and the results of surveys on appliance use. He also testified that DTE's forecasts are accurate within a percentage point.

[743] See 5 tr 1288-1289.
[744] See 5 Tr 1289-1292.

B. <u>Nuclear Surcharge</u>

Mr. Bloch presented revisions to the nuclear surcharge in Schedule F6 of Exhibit A-14. He testified that increases are due to increased site securitization and radiation protection costs supported by Mr. Colonnello combined with lower forecast jurisdictional sales.[745] No party objected to the revised nuclear surcharge and this PFD recommends it be adopted.

C. <u>Line Extension Rate</u>

Mr. Bloch also testified that DTE proposes to revise its line extension rate.[746] No party objected and this PFD recommends the request be granted.

D. <u>Accounting Requests</u>

Ms. Uzenski identified six accounting requests DTE would like the Commission to authorize.[747] Only two of those, the regulatory asset for the ETTP and the reclassification of the SRP expenses, were controversial. Those are discussed above. In addition, one of Ms. Uzenski's requests related to the treatment of obsolete inventory and has been resolved according to the Commission's decision in Case No. U-18033. The remaining three requests include: 1) continuation of the OPEB deferral accounting; 2) capitalization of demand-side management equipment; and 3) the inclusion of fuel costs associated with negative net-generation activities at single unit generators as a power supply cost to be addressed in PSCR proceedings. No party objected to the remaining three requests and this PFD therefore recommends that they be approved.

---

[745] See 3 Tr 471.
[746] See 3 Tr 473.
[747] See 4 Tr 848.

E. Reporting Requirements

Staff also requested that the company conduct biannual meetings with Staff to discuss environmental projects. This PFD finds Staff's request reasonable and recommends that the Commission endorse it.

Staff also requested that the Commission require DTE to report on its AMI program. Mr. Matthews presented the proposed reporting requirements in his Exhibit S-10. He explained that the proposed metrics are necessary for Staff to fully analyze and track the progression to a smarter grid and to ensure benefits are maximized.[748] Mr. Sitkauskas testified that DTE agrees with the spirit of the request, but does not believe that all identified items are necessary, and further does not believe DTE would be able to provide data responses to a few of the metrics.[749] Mr. Sitkauskas recommended that the company meet with Staff to develop a mutually acceptable scope and format, and DTE renews this recommendation in its brief.[750] In its brief, Staff instead explains why it wants to retain its reporting metrics as provided in Exhibit S-10:

> Staff believes that all 43 of the proposed smart grid metrics are appropriate, and the Company should provide Staff with the proposed report, including the clarifications and format Staff has provided in its direct testimony. (5 TR 1498.) Staff recommends that at the time of the first report, Staff and DTE Electric can discuss changes to the metrics that might be necessary. Staff's intention is to be consistent with what Staff has recommended in the Company's current gas rate case (MPSC Case No. U-17999). In order to keep a single consistent report and avoid duplication of work between the Company's gas and electric sides, the ALJ and the Commission should require the Company to provide the AMI report as proposed by Staff.[751]

[748] See 5 Tr 1497.
[749] See 4 Tr 1045-1046.
[750] See DTE brief, page 63.
[751] See Staff brief, page 110.

This PFD recommends that the Commission require DTE to address each of the proposed smart grid metrics in its first report, as Staff requests, with explanations provided regarding any data that is not available. Staff and DTE should be encouraged to continue to resolve issues regarding appropriate changes to the metrics.

XI.

CONCLUSION

Based on the foregoing discussion, this PFD recommends that the Commission adopt the findings, conclusions and recommendations set forth above, including the findings and recommendations on rate base, capital structure, cost of capital, and operating revenues and expenses leading to an estimated revenue deficiency of approximately $187 million, with an authorized return on equity of 10.0% and an overall cost of capital of 5.52%, as well as recommendations regarding various accounting requests, ratemaking mechanisms, cost of service allocations, rate design, and tariff modifications, as well as recommendations for additional reporting and analysis.

MICHIGAN ADMINISTRATIVE HEARING SYSTEM
For the Michigan Public Service Commission

Sharon L. Feldman

Sharon L. Feldman
Administrative Law Judge

November 21, 2016
Lansing, Michigan

Michigan Public Service Commission **Appendix A**
DTE Electric Company **PFD**
Projected Revenue Deficiency (Sufficiency)
Projected 12 Month Period Ending July 31, 2017
($000's)

	(a)	(b)	(c)	(d)	(e)
Line No.	**Description**	**Source**	**DTE Total Electric (Reply Brief)**	**ALJ Adjustments**	**ALJ Projection**
1	Rate Base	Exh. S2, Sch. B1	14,444,514	(198,767)	14,245,747
2	Adjusted Net Operating Income	Exh. S3, Sch. C1	625,679	46,275	671,955
3	Overall Rate of Return	Line 2 ÷ Line 1	4.33%	0.39%	4.72%
4	Projected Rate of Return	Exh. S4, Sch. D1	5.71%	-0.19%	5.52%
5	Income Requirements	Line 1 x Line 4	824,074	(38,093)	785,981
6	Income Deficiency (Sufficiency)	Line 5 - Line 2	198,395	(84,369)	114,026
7	Revenue Conversion Factor	Exh. S3, Sch. C2	1.6394	-	1.6394
8	Revenue Deficiency / (Sufficiency)	Line 6 x Line 7	325,245	(138,312)	186,933

Michigan Public Service Commission **Appendix B**
DTE Electric Company **PFD**
Projected Rate Base
Projected Average Balances Period Ending July 31, 2017
Annual Simple Average Balances
($000's)

	(a)	(b)	(c)	(d)	(e)
Line No.	**Description**	**Source**	**DTE Total Electric (Reply Brief)**	**ALJ Adjustments**	**ALJ Projection**
1	Utility Plant in Service:				
2	Plant in Service	Exh. S2, Sch. B2	19,165,392	(76,066)	19,089,326
3	Plant Held for Future Use	Exh. S2, Sch. B2	224	-	224
4	Construction Work in Progress	Exh. S2, Sch. B2	967,805	(1,004)	966,801
5	Acquisition Adjustments	Exh. S2, Sch. B2	132,034	-	132,034
6	Total Utility Plant		20,265,455	(77,071)	20,188,384
7	Depreciation Reserve	Exh. S2, Sch. B3	(7,266,889)	870	(7,266,019)
8	Net Utility Plant		12,998,566	(76,201)	12,922,365
9	Net Capital Lease Property	Exh. S2, Sch. B5.1	3,620	-	3,620
10	Net Nuclear Fuel Property	Exh. S2, Sch. B5.1	167,994	-	167,994
11	Total Utility Property and Plant		13,170,180	(76,201)	13,093,979
12	Less: Capital Lease Obligations	Line 8	(3,620)	-	(3,620)
13	Net Plant		13,166,560	(76,201)	13,090,359
14	Allowance for Working Capital	Exh. S2, Sch. B4	1,277,954	(122,565)	1,155,388
15	Total Projected Rate Base		14,444,514	(198,766)	14,245,747

Michigan Public Service Commission **Appendix C**
DTE Electric Company **PFD**
Adjusted Net Operating Income
Projected 12 Month Period Ending October 31, 2017
($000)

		Revenue				Expenses						NOI			
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
Line No.	Description (Witness)	Electric Sales Revenue	Other	Revenue Adjustments	Total	Fuel & PP	O&M	Depr & Amort	Property & Other Tax	State & Local IT	FIT	NOI	AFUDC	Other	Adjusted NOI
	Company Filed (Reply Brief)										237,711				
1	Operating Income	4,467,287	81,247	24,402	4,572,936	1,402,331	1,319,810	701,546	314,304	51,404	186,307	597,234	31,953	(3,508)	625,679
	ALJ Adjustments														
2	Sales Revenue (Revere)			720	720					44	236	439			439
3	Steam Power Generation (Shi)				-		(10,709)			659	3,517	6,532			6,532
4	Fuel Supply & MERC Fuel Handiling (Shi)				-		(409)			25	134	249			249
5	Nuclear Power Gen - Inflation (Shi)				-		(4,975)			306	1,634	3,035			3,035
6	Nuclear Power Generation (Shi)				-		(14,287)			880	4,693	8,715			8,715
7	Hydraulic Power Generation (Shi)				-		(341)			21	112	208			208
8	Other Power Supply (Shi)				-		(466)			29	153	284			284
9	Distribution (Derkos)				-		10,408			(641)	(3,419)	(6,349)			(6,349)
10	Property Tax (Welke)				-				(10,283)	633	3,377	6,272			6,272
11	Pension & Benefits (Welke)				-		(1,556)			96	511	949			949
12	Corporate: Incentive Compensation (Welke)				-		(22,982)			1,415	7,548	14,019			14,019
13	Corporate: Property Insurance (Welke)				-		(1,441)			89	473	879			879
14	Corporate: Economic Development (Nichols)				-		(3,000)			185	985	1,830			1,830
15	Corporate: Inflation (Welke)				-		(7,074)			436	2,323	4,315			4,315
16	COLA Amortization Adjustment				-			170		(10)	(56)	(104)			(104)
17	Depreciation (Cap Ex Adjustments)				-			(4,254)		262	1,397	2,595			2,595
18	Active Healthcare (AG)				-		(6,200)			382	2,036	3,782			3,782
19					-					-	-	-			-
20	Tax Calculation Difference (See Note 1)				-					-	(243)	243			243
21					-					-	-	-			-
22	Proforma Interest				-					255	1,362	(1,617)			(1,617)
23	Interest Synchronization	-	-	-	-	-	-	-	-	-	2	(2)	-	-	(2)
24	**Total Adjustments**	-	-	720	720	-	(63,032)	(4,084)	(10,283)	5,064	26,779	46,275	-	-	46,275
25	**Net Operating Income - Test Year**	4,467,287	81,247	25,122	4,573,656	1,402,331	1,256,778	697,462	304,021	56,469	213,086	643,510	31,953	(3,508)	671,955

Notes:
1 There is a difference in the tax calculation by Staff and the Company in Reply Briefs. The PFD adopts the Staff tax calculation, but provides for opportunity for clarification of the Company calculation in Exceptions.

Michigan Public Service Commission
DTE Electric Company
Projected Rate of Return Summary
For Period Ending July 31, 2017

Appendix D
PFD

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		Capital Structure				Weighted Costs			
Line No.	Description	Amounts ($000)	Percent Permanent Capital	Percent of Total Capital	Cost Rate %	Permanent Capital	Total Cost %	Conversion Factor	Pre-Tax Return
1	Long-Term Debt	5,430,219	50.00%	37.50%	4.61%	2.30%	1.73%	100.000%	1.73%
2	Preferred Stock	0	0.00%	0.00%	0.00%	0.00%	0.00%	163.939%	0.00%
3	Common Shareholders' Equity	5,429,704	50.00%	37.49%	10.00%	5.00%	3.75%	163.939%	6.15%
4	Total	10,859,923	100.00%			7.30%			
5	Short-Term Debt	286,263		1.98%	1.58%		0.03%	100.000%	0.03%
6	Investment Tax Credit (ITC) - Debt	9,488		0.07%	4.61%		0.00%	100.000%	0.00%
7	Investment Tax Credit (ITC) - Equity	9,488		0.07%	10.00%		0.01%	163.939%	0.01%
8	Total Investment Tax Credit (ITC)	18,976							
9	Deferred Income Taxes (Net)	3,316,387		22.90%	0.000%		0.00%		0.00%
10	Total	14,481,549		100.00%			5.52%		7.92%